DIRECT TESTIMONY AND EXHIBIT OF

ANTHONY M. SANDONATO

ON BEHALF OF

THE SOUTH CAROLINA OFFICE OF REGULATORY STAFF

DOCKET NO. 2019-226-E

IN RE: SOUTH CAROLINA ENERGY FREEDOM ACT (HOUSE BILL 3659) PROCEEDING RELATED TO S.C. CODE ANN. SECTION 58-37-40 AND INTEGRATED RESOURCE PLANS FOR DOMINION ENERGY SOUTH CAROLINA, INCORPORATED

Q. PLEASE STATE YOUR NAME, BUSINESS ADDRESS AND OCCUPATION.

A. My name is Anthony Sandonato. My business address is 1401 Main Street, Suite 900, Columbia, South Carolina, 29201. I am employed by the South Carolina Office of Regulatory Staff ("ORS") in the Energy Operations Division as a Senior Regulatory Manager.

Q. PLEASE STATE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.

A. I received my Bachelor of Science in Nuclear Engineering from North Carolina State University in 2011. Prior to my employment with ORS, I was employed as an analyst with a global professional, technology, and marketing service firm working with large investor-owned utilities on energy efficiency program design and implementation. I joined ORS in 2016, and, in October 2019, I was promoted to my current position in the Energy Operations Division.

Q. HAVE YOU TESTIFIED BEFORE THE PUBLIC SERVICE COMMISSION OF SOUTH CAROLINA ("COMMISSION")?

A. Yes. I have previously testified before the Commission.

Q. WHAT IS THE MISSION OF ORS?

A. ORS represents the public interest as defined by the South Carolina General Assembly as:

> [T]he concerns of the using and consuming public with respect to public utility services, regardless of the class of customer, and preservation of continued investment in and maintenance of utility facilities so as to provide reliable and high-quality utility services.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to set forth and support ORS's recommendations resulting from the examination and review of Dominion Energy South Carolina, Incorporated's ("DESC" or "Company") Integrated Resource Plan ("IRP") and associated filings in this docket to determine compliance with certain sections of the South Carolina Energy Freedom Act ("Act 62" or the "Act"). ORS retained the consulting services of J. Kennedy and Associates, Inc. ("Kennedy and Associates") to assist in the review and analysis of the Company's IRP.

Q. WAS THE EXAMINATION AND REVIEW OF DESC'S FILINGS PERFORMED BY YOU OR UNDER YOUR SUPERVISION?

A. Yes. The review to which I testify was performed by me or under my supervision.

Q. PLEASE EXPLAIN EXHIBIT AMS-1.

A. Exhibit AMS-1 is the Review of Dominion Energy South Carolina, Inc. 2020 Integrated Resource Planning Report (the "Report"). The Report was developed for ORS by Kennedy and Associates and provides a detailed analysis of the DESC IRP. The direct testimonies of ORS witnesses Philip Hayet, Lane Kollen and Stephen J. Baron discuss their respective reviews, analyses and recommendations.

Q. PLEASE DETAIL THE CRITERIA BY WHICH YOU EVALUATED THE COMPANY'S IRP.

A. ORS relied on the requirements provided in S.C. Code Ann. §58-37-40(B)(1) (Rev. 2019)**,** which requires an IRP for an electrical utility to include the following:

> (a) a long-term forecast of the utility's sales and peak demand under various reasonable scenarios;
> (b) the type of generation technology proposed for a generation facility contained in the plan and the proposed capacity of the generation facility, including fuel cost sensitivities under various reasonable scenarios;
> (c) projected energy purchased or produced by the utility from a renewable energy resource;
> (d) a summary of the electrical transmission investments planned by the utility;
> (e) several resource portfolios developed with the purpose of fairly evaluating the range of demand-side, supply-side, storage, and other technologies and services available to meet the utility's service obligations. Such portfolios and evaluations must include an evaluation of low, medium, and high cases for the adoption of renewable energy and cogeneration, energy efficiency, and demand response measures, including consideration of the following:
> (i) customer energy efficiency and demand response programs;
> (ii) facility retirement assumptions; and
> (iii) sensitivity analyses related to fuel costs, environmental regulations, and other uncertainties or risks;
> (f) data regarding the utility's current generation portfolio, including the age, licensing status, and remaining estimated life of operation for each facility in the portfolio;
> (g) plans for meeting current and future capacity needs with the cost estimates for all proposed resource portfolios in the plan;
> (h) an analysis of the cost and reliability impacts of all reasonable options available to meet projected energy and capacity needs; and,
> (i) a forecast of the utility's peak demand, details regarding the amount of peak demand reduction the utility expects to achieve, and the actions the utility proposes to take in order to achieve that peak demand reduction.

Q. DOES THE COMPANY'S IRP COMPLY WITH S.C. CODE ANN. §58-37-40(B)(1)?

A. Yes. The Company's IRP as filed with the Commission includes the elements required under the Act. Each element of Act 62 and a corresponding analysis to DESC's IRP compliance is discussed in detail in the Report contained in Exhibit AMS-1.

Q. PLEASE SUMMARIZE S.C. CODE ANN. §58-37-40(C).

A. Section 58-37-40(C), as revised by Act 62, identifies the following factors that an IRP should appropriately balance to determine if the Company's plan is the most reasonable:

> (a) resource adequacy and capacity to serve anticipated peak electrical load, and applicable planning reserve margins;
> (b) consumer affordability and least cost;
> (c) compliance with applicable state and federal environmental regulations;
> (d) power supply reliability;
> (e) commodity price risks;
> (f) diversity of generation supply; and
> (g) other foreseeable conditions that the commission determines to be for the public

Q. PLEASE SUMMARIZE ORS'S RECOMMENDATION RELATED TO THE COMPANY'S IRP

A. ORS recommends the Company be required to modify the 2020 IRP. Each ORS recommendation listed below is discussed in more detail in the Report and testimonies of ORS witnesses Barron, Kollen and Hayet. The specific modifications recommended by ORS including the corresponding item number as found in the Executive Summary of the Report are listed in the table below.

Item	Recommendations for this IRP
11	The Company should update its Wateree 2 analysis by correcting errors and properly accounting for the insurance payout.

Item	Recommendations for this IRP
12	The Company should include a discussion of the Wateree 2 outage and the decision it makes to either repair or retire the unit.
13	The Company should review its assumptions regarding long-term continuing capital cost de-escalation of renewable energy projects
14	The Company should review its capital cost assumptions for its internal combustion turbine ("ICT") resource in this IRP to ensure that the costs are reasonable given its assumption appears to be much lower that other industry estimates.
15	The Company should include fixed operation and maintenance ("O&M") expenses for new owned solar and BESS resource additions in this and future IRPs.
16	The Company should review its O&M assumptions for all combined cycle and ICT resource options and revise those assumptions in this IRP if they are found to be unreasonable or in error.
21	The Company should escalate its cost assumptions for short-term winter capacity purchases.
22	The Company should update its IRP to include tables that rank all RPs under all sensitivities.
23a	The Company should correct errors in the transfer of PROSYM expenses to the Excel revenue requirement models.
23b	The Company should include capitalized interest ("AFUDC") in its revenue requirement modeling.
23c	The Company should correct errors in calculations that escalated capital expenditures to future dollars for new resource additions and for Wateree and Williams Effluent Limitation Guidelines ("ELG") capital expenditures/plant additions
23d	The Company should include incremental capital expenditures/plant additions for existing resources and new resources after commercial operation, with the sole exception of the Wateree and Williams ELG capital expenditures/plant additions.
23e	The Company should replace each new BESS resource after its assumed ten year operating life.

Item	Recommendations for this IRP
23f	The Company should properly account for Investment Tax Credits for new owned solar and BESS resource additions.
23g	The Company should include dismantlement costs, site restoration costs, and incremental transmission costs necessary for post-retirement voltage support for existing resources, particularly resources studied for possible early retirement.
23h	The Company should use the correct depreciable life assumption for ELG capital expenditures/plant additions.
23i	The Company should include ICT natural gas firm transportation costs in any of the RPs.
23j	The company should include the capital revenue requirements of the new ICT resource addition in 2040 in RP8.
23k	The Company should review its escalation calculations for final ten (10) years of the study period as discussed in the Report.

Q. WILL YOU UPDATE YOUR DIRECT TESTIMONY BASED ON INFORMATION THAT BECOMES AVAILABLE?

A. Yes. ORS fully reserves the right to revise its recommendations via supplemental testimony should new information not previously provided by the Company, or other sources, becomes available.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.

Review of Dominion Energy South Carolina, Inc. 2020 Integrated Resource Plan
Docket No. 2019-226-E

South Carolina
Office of Regulatory Staff

July 10, 2020

Review of Dominion Energy South Carolina, Inc. 2020 Integrated Resource Plan

Pursuant to Section 58-37-40, South Carolina Code of Laws

July 10, 2020

Prepared for the South Carolina Office of Regulatory Staff
by
J. Kennedy and Associates, Inc.

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Executive Summary

The South Carolina Office of Regulatory Staff ("ORS") provides this Report to summarize the review of Dominion Energy South Carolina, Inc.'s ("DESC" or "Company") 2020 Integrated Resource Plan ("IRP") filed February 28, 2020, in Docket No. 2019-226-E. ORS, with the assistance of J. Kennedy and Associates, Inc. ("JKA"), evaluated DESC's IRP to determine if the statutory requirements of S.C. Code Ann. §58-37-40 ("Section 40"), as amended by the South Carolina Energy Freedom Act ("Act 62"), and the requirements of the Public Service Commission of South Carolina's ("Commission") Order No. 98-502 were met by DESC. This Report also addresses the Company's analyses using assumptions provided by the South Carolina Solar Business Alliance ("SCSBA"), as well as subsequent analyses developed by DESC that modified certain critical aspects of the IRP framework reflected in the DESC IRP.[1]

Act 62 was signed into law by Governor McMaster on May 16, 2019. Act 62 revised the IRP requirements included in Section 40 to establish a "least cost" resource plan ("RP") standard and revise the utility's IRP information requirements. Act 62 established specific information requirements that address the peak load and energy forecasts, reliability, new resource alternatives, renewable resources, and existing resource retirements. Act 62 also added other substantive and procedural requirements.

Act 62 requires the Commission to determine the "most reasonable and prudent means of meeting the electrical utility's energy and capacity needs as of the time the plan is reviewed."[2] Act 62 provides seven (7) factors for the Commission to consider in the evaluation of the resource plans in the DESC IRP. Act 62 also states that any resource plan accepted by the Commission "shall not be determinative of the reasonableness or prudence of the acquisition or construction of any resource or the making of any expenditure."[3] It further states that the utility retains the burden to prove in a future cost recovery proceeding that any investment and expenditure it makes is reasonable and prudent.

The DESC IRP in this proceeding is the first to address the Act 62 requirements and the Company's third filing since it terminated construction of the V.C. Summer 2 and 3 nuclear units in July 2017. The Company states that the overall objective of its IRP is to "provide safe reliable cost-effective energy to the Company's customers while complying with all laws and regulations," and that the Company must remain flexible and agile with respect

[1] In ORS Audit Information Request ("AIR") 1-15, the Company reported that the Wateree 2 coal-fired unit suffered a major outage from a hydrogen explosion on February 19, 2020. The Company also stated that since the IRP was filed, it completed a repair/replace/retirement study and concluded it would be more economic to replace damaged equipment at Wateree 2 (requiring 12 to 24 months) than to retire it.
[2] S.C. Code Ann. § 58-37-40(C)(2).
[3] S.C. Code Ann. § 58-37-40(C)(4).

to developing RPs. While the Company did consider a range of plausible paths that it ultimately could elect to pursue, ORS disagrees with many of the assumptions and methodologies that the Company reflected in its IRP.

The DESC IRP identifies the least cost RP among a set of alternative RPs and sensitivities that the Company considered and reviewed; however, ORS is aware through discovery that the Company subsequently evaluated other RPs and identified a lower cost RP in studies it conducted to evaluate the recent major outage of the Wateree 2 unit.[4] In part, this lower cost RP resulted from the correction of errors and updates to data assumptions, including fuel costs and firm transportation expenses.

The least cost RP reflected in the DESC IRP, and the lower cost RP subsequently identified through discovery, assume minimal peak load growth; implementation of the 2019 Potential Study Demand Side Management ("DSM") programs approved by the Commission in December 2019;[5] which the Company has used for its "medium" DSM case; no carbon tax or other new environmental regulations; a base gas price forecast starting with New York Mercantile Exchange ("NYMEX") futures for the first three (3) years and then escalated in subsequent years; the repair and return to service of Wateree 2; no early retirements of existing resources; the addition of 973 megawatts ("MW") of solar power purchase agreement resources already under contract; and no other additions of new resources until 2035.

Although there is no immediate need for decisions to acquire or build new resources in this IRP, the Company identified RP2 as the least cost preferred path forward for its long-term planning compared to seven other RPs that considered various other combinations of potential types of new resource additions and existing resource retirements, as well as other assumptions and DSM, natural gas price, and carbon dioxide ("CO_2") price sensitivities.[6] RP2 assumes there will be no early retirements of existing resources and no new resource additions until 2035. RP2 in the IRP assumes the new resource addition in 2035 will be a natural gas-fired internal combustion turbine ("ICT") unit and that all

[4] In ORS AIR 6-4, the Company elaborated on the Wateree 2 forced outage that occurred on February 19, 2020. As a result of that forced outage, the Company conducted a repair/replace/retirement study, which resulted in a decision to replace the Wateree 2 generator stator mid-section and to rewind the existing generator field. It based that decision on a different long-term resource plan than RP2, which included a CC unit in 2035 instead of an ICT unit in that year.

[5] Order No. 2019-880.

[6] See Direct Testimony of Eric Bell, pg. 25, at ln. 19.

subsequent new resource additions in 2044 and beyond will also be ICTs. RP2 assumes no new solar resources beyond the additions in 2020 and 2021 that are under contract.

ORS is unable to verify at this time that RP2, or any of the other RPs presented by the Company, is the "most reasonable and prudent means of meeting the electrical utility's energy and capacity needs as of the time the plan is reviewed," the standard set forth in Section 40, as amended by Act 62.[7] This is due to numerous and significant errors reflected in all eight (8) RPs presented in the filing under all risk sensitivities analyzed, as well as the five (5) RPs and sensitivities created using assumptions provided by the SCSBA. This is also due to the fact that the Company identified a lower cost RP compared to RP2 in its Wateree 2 analyses. However, the Wateree 2 results are also unreliable as those studies contain some of the same errors that were identified in the IRP analyses, and because the Company introduced new errors in those studies as well.

ORS recommends the Company be required to modify the IRP as filed to address the problems identified and described by ORS in the subsequent sections of this report, correct the errors in the eight (8) RPs and the sensitivities presented in the IRP, present the results of the revised RPs and sensititvities, and identify and present a revised RP as the least cost RP. The Company also should correct and present revised versions of the Wateree 2 analyses and the RPs developed using assumptions provided by the SCSBA. In addition, ORS recommends the Company be required to improve its IRP planning process, including the modeling tools and methodologies used to develop the IRP in future IRPs.

ORS provides the following summary of its recommendations detailed in the subsequent sections of this report. These recommendations address the IRP process, load and energy forecasts, generic resource profiles, production cost and revenue requirements modeling, and assumptions relied on to develop the RPs and the resulting comparative metrics. Many recommendations address concerns and errors that should be addressed in the form of a modified IRP in this proceeding. These recommendations are designated with an "N" to indicate the Company should act now to modify the IRP. Other recommendations address concerns that should be addressed in the next annual update IRP, but no later than the next comprehensive IRP in 2023. These recommendations are no less important, but recognize that the implementation and use of new modeling tools and methodologies will require additional time and cannot reasonably be accomplished

[7] S.C. Code Ann. § 58-37-40(C)(2).

in this proceeding.[8] The recommendations are designated with an "L" to indicate DESC should incorporate the recommendation in the next annual update IRPs in 2021 and 2022 or in the next comprehensive IRP in 2023 at the latest.

Load and Energy Forecasts Recommendations

1. The Company should provide a more thorough presentation of its load and energy forecasting methodology in future IRPs. **(L)**

2. The Company should improve its residential and commercial peak load forecast methodology to reflect the type of behavioral factors that are likely to impact peak demand over time, such as changes in appliance saturation and appliance efficiency improvements, other than caused exclusively by federally mandated requirements. **(L)**

3. The Company should expand the number of sensitivities it analyzes to include both DSM scenarios and actual load growth scenarios in the expansion plan and economic analyses it performs in future IRPs. **(L)**

Reserve Margin Planning Recommendations

4. The Company should include a detailed analysis of its reserve margin methodology in future IRPs, which could be included as an appendix to the IRP report. At a minimum, the Company should provide:

   a. Additional explanation of the Company's dual reserve margin criteria (base reserves, peaking reserves). There is an insufficient explanation of the applicability of either criterion in the IRP Report and in the testimony of DESC witnesses. **(L)**

   b. A stronger foundation for inclusion of the Virginia-Carolina ("VACAR") Reserve Sharing Agreement ("RSA") operating reserve obligation as a component in the calculation of its long term resource planning reserve margin. The VACAR operating reserve obligation is a short term operating reserve obligation, not a long-term planning criteria and does not appear to be consistent with general industry practice. **(L)**

[8] For example, the Company is investigating new models for future IRPs, including a resource optimization model, which ORS considers to be a high priority item. Preferably, the new model should be implemented and used to develop the RPs in the next two (2) annual IRPs, but certainly should be used to develop the RPs in the next comprehensive IRP in 2023.

5. With regard to reserve margin modeling methodologies in future IRPs:

   a. The Company should consider utilizing an optimal economic based reserve margin methodology that considers the cost to customers of unserved load and energy compared to the cost of meeting various levels of reliability. **(L)**

   b. The Company should include a traditional Loss of Load Expectation ("LOLE") analysis and present the results of a more comprehensive LOLE analysis that includes probability assessments of the impact on peak loads of varying weather conditions and also considers the impacts of a reasonable amount of tie line support from neighboring utilities. **(L)**

Demand Side Management Recommendation

6. The Company should only use DSM assumptions for its RPs and sensitivities that it has confidence in and believes are reasonable and achievable. **(L)**

Natural Gas Price Forecasts Recommendations

7. The Company should reexamine its natural gas price forecasting methodology, investigate alternative approaches for use in future IRPs, and perform a comparison to other publicly available forecasts to evaluate the reasonableness of its forecasts for use in future IRPs. **(L)**

8. The Company should address the availability and constraints of natural gas pipeline capacity and supply on the timing, size, and location of potential new combined cycle ("CC") and ICT resource additions in future IRPs. **(L)**

CO_2 Price Forecasts Recommendation

9. The Company should examine additional CO_2 price sensitivities by including a third CO_2 forecast, consistent with industry practice, in future IRPs. **(L)**

Existing System Resources Recommendations

10. The Company should conduct a detailed retirement study and should ensure that it corrects the modeling errors identified in this report. These studies should identify proper input assumptions to capture all costs and savings that would be incurred in the retirement analysis. The studies should address all potential early retirement candidates including the Williams, Wateree, Urquhart, and McMeekin coal, gas-fired steam turbine and gas-fired combustion turbine ("CT") units. **(L)**

11. The Company should conduct additional modeling analyses of the Wateree 2 alternatives, in which it corrects the numerous PROSYM and capital revenue requirement errors that ORS identified and are discussed further below. In addition, the Company should include insurance payout assumptions in both the Wateree 2 retirement cases and Wateree 2 continuation cases, or it should remove the insurance payout assumption from both analyses. Finally, the Company should conduct analyses with the Urquhart and McMeekin gas fired steam turbine units retired on their probable retirement dates. **(N)**

12. The Company should include a discussion of the Wateree 2 outage and the evaluation that it conducted to decide when to retire or to repair the unit and provide justification for any decision to continue to operate the unit. **(N)**

<u>Generic Resource Options Recommendations</u>

13. The Company should review its assumptions regarding long-term continuing capital cost de-escalation of renewable energy projects. **(N)**

14. The Company should review its capital cost assumptions for its ICT resource in this IRP to ensure that the costs are reasonable given its assumption appears to be much lower than other industry estimates. **(N)**

15. The Company should include fixed operation and maintenance ("O&M") expenses for new owned solar and battery energy storage system ("BESS") resource additions in this and future IRPs. **(N)**

16. The Company should review its O&M assumptions for all CC and ICT resource options and revise those assumptions in this IRP if they are found to be unreasonable or in error. **(N)**

17. The Company should reevaluate its assumption regarding its reliance on generic winter capacity purchases and ensure that any decision to add those capacity purchases is made based on the availability and economics of the capacity purchases. **(L)**

<u>Resource Planning Recommendations</u>

18. The Company should place a high priority on completing implementation of the least cost optimization model prior to the 2021 IRP Update and for use in that Update as well as future IRPs. **(L)**

19. The Company should expand the number of RPs evaluated for future IRPs. **(L)**

20. The Company should develop alternative expansion plans for different gas price and CO_2 sensitivities in future IRPs. **(L)**

21. The Company should escalate its cost assumptions for short-term winter capacity purchases. **(N)**

22. The Company should update its IRP to include tables that rank all RPs under all sensitivities. **(N)**

23. The Company should correct the following errors in the Excel revenue requirement modeling and ranking of RPs in the IRP, RPs using assumptions provided by the SCSBA, and subsequent RPs used to evaluate repair/replace and return to service or retire Wateree 2 studies.[9] **(N)**

    a. Misstated production expenses due to errors in the transfer of PROSYM expenses to the Excel models used to perform economic analyses and rank RPs.

    b. Understated costs of new resources due to failure to include capitalized interest (Allowance for Funds Used During Construction, referred to as "AFUDC").

    c. Misstated incremental costs of new resource additions and the incremental costs of the Wateree and Williams Effluent Limitation Guidelines ("ELG") capital expenditures/plant additions due to errors in calculations affecting escalation of capital expenditures to future dollars.

    d. Understated incremental costs of existing resources and new resource additions due to failure to include post-in service capital expenditures/plant additions, with the sole exception of the Wateree and Williams ELG capital expenditures/plant additions.

    e. Understated cost of new owned BESS resource additions due to failure to replace each new BESS resource after its assumed ten (10) year operating life.

    f. Overstated costs of new owned solar and BESS resource additions due to failure to reflect the Investment Tax Credit ("ITC").

[9] The errors are described in greater detail in subsequent sections of the Report.

g. Understated incremental costs to retire existing resources due to omission of dismantlement costs, site restoration costs, and incremental transmission costs necessary for post-retirement voltage support.

h. Overstated incremental costs to continue operating Wateree and Williams due to incorrect depreciable life assumption on ELG capital expenditures/plant additions.

i. Understated incremental costs of ICTs due to failure to include natural gas firm transportation costs in any of the RPs.

j. Excluded cost of new ICT resource addition in 2040 in RP8.

k. Misstated production costs for the final ten (10) years of the study period due to use of inappropriate escalation factors.

Transmission Planning Recommendation

24. The Company should complete the studies to address the changes to the transmission system and the related investment infrastructure costs necessary for new solar resource additions and include that information and a description of its studies and conclusions in the next comprehensive IRP in 2023. **(L)**

Distribution Resource and Integrated System Operations Plans Recommendation

25. The Company should supply additional information about distribution resource plans or integrated system operational plans. **(L)**

Other Considerations and Recommendations

26. The Company should create a stakeholder process to provide opportunities for stakeholder involvement and input in the formulation of future IRPs. **(L)**

27. The Company should develop a three-year action plan that identifies all actions the Company intends to take in order to implement its IRP in each future update and comprehensive IRP. **(L)**

Evolution of the IRP Process in South Carolina

Initiation of the IRP Process

The Commission first initiated a generic proceeding involving the jurisdictional Electric Utilities in June 1987 to address least-cost resource procedures based on a comprehensive planning approach.[10] The Commission first required electric utilities to file IRPs in September 1989.[11]

The Commission approved a more formal IRP process in October 1991.[12] The Commission required utilities to file detailed IRPs every three (3) years and file a short term action plan in the intervening years. In addition to the Commission's IRP procedures, the South Carolina legislature passed a bill (Act 449) known as the South Carolina Energy Conservation and Efficiency Act of 1992, adding S.C. Code Ann. § 58-37-40.[13] The definition of an IRP adopted for use in South Carolina is found in S.C. Code Ann. § 58-37-10(2):

> "Integrated resource plan" means a plan which contains the demand and energy forecast for at least a fifteen-year period, contains the supplier's or producer's program for meeting the requirements shown in its forecast in an economic and reliable manner, including both demand-side and supply-side options, with a brief description and summary cost-benefit analysis, if available, of each option which was considered, including those not selected, sets forth the supplier's or producer's assumptions and conclusions with respect to the effect of the plan on the cost and reliability of energy service, and describes the external environmental and economic consequences of the plan to the extent practicable. For electrical utilities subject to the jurisdiction of the South Carolina Public Service Commission, this definition must be interpreted in a manner consistent with the integrated resource planning process adopted by the commission. For electric cooperatives subject to the regulations of the Rural Electrification Administration, this definition must be interpreted in a manner

[10] Docket No. 87-223-E, Order No. 87-569, June 18, 1987.
[11] Docket No. 87-223-E, Order No. 89-521, May 17, 1989.
[12] Docket No. 87-223-E, Order No. 91-885, October 21, 1991. Attachment A to the Order contained the detailed IRP requirements. Another Order granting clarification and modification was issued on November 6, 1991 (Order No. 91-1002).
[13] www.scstatehouse.gov/billsearch.php?billnumbers=1273&session=109&summary=B

> consistent with any integrated resource planning process prescribed by Rural Electrification Administration regulations.

Until 1998, utilities followed the IRP requirements established by the Commission's 1991 order. On February 3, 1998, Duke Energy filed a petition to modify the IRP requirements, which led the Commission to re-evaluate its IRP procedures.[14] On July 2, 1998, the Commission issued Order No. 98-502, which established a simplified set of IRP requirements based on what the Commission observed at the time to be "the changing nature and deemphasis of Integrated Resource Planning."[15] More recently, the state legislature passed Act 62 also known as the Energy Freedom Act of 2019, which addressed many issues associated with utility planning, including updating and re-emphasizing IRP requirements.[16]

Act 62 IRP Requirements

Act 62 was signed into law in May 2019. Act 62 updated Section 40 by changing some requirements and adding others that affected not only the electric utilities, but also the Commission, ORS and the State Energy Office ("SEO").

Section 40 now requires electric utilities to file IRPs that provide more detailed information to the Commission and other parties, and to post the IRPs on both the Commission's and the utilities' websites. Electric utilities are required to file IRPs at least every three (3) years, and to file annual updates with specific information requirements in the intervening years.[17] Section 40(B)(1) sets forth the required information and Section 40(B)(2) sets forth the additional optional information.

Section 40 now requires the Commission to establish a proceeding to review each electric utility's IRP. Interested parties are permitted to intervene and submit discovery. Section 40(C)(1) states the new requirements are intended to allow interested parties to obtain "evidence concerning the integrated resource plan, including the reasonableness and prudence of the plan and alternatives to the plan."

Sections 40(C)1 and (C)2 state the Commission shall issue a final order within 300 days that approves the utility's IRP as is, if the Commission "determines that the proposed integrated resource plan represents the most reasonable and prudent means of meeting the electrical utility's energy and capacity needs as of the time the plan is reviewed."

[14] February 3, 1998. Docket No. 87-223-E, Order No. 98-502, July 2, 1998.
[15] Docket No. 87-223-E, Order No. 98-150, February 25, 1998.
[16] Act 62 became effective on May 16, 2019.
[17] S.C. Code Ann. § 58-37-40(D)(1).

However, if the Commission finds that the IRP does not meet that standard, then the Commission is required to either order the utility to make specific modifications to its IRP or reject the IRP entirely. If the Commission makes one (1) of these two (2) determinations, Section 40(C)(3) provides procedures and a timeline that requires the utility to resubmit its IRP and ORS to review the revisions and report its findings to the Commission. Then, the Commission "at its discretion may determine whether to accept the revised integrated resource plan or to mandate further remedies that the Commission deems appropriate."

Section 40(C)2 directs the Commission to consider seven (7) factors as it evaluates whether the IRP is "the most reasonable and prudent means of meeting energy and capacity needs" and determine whether the IRP should be accepted, modified or rejected.

The procedure for reviewing annual updates filed in the two (2) intervening years is different than for the comprehensive filing that utilities must make every three (3) years. For the annual updates, ORS is required to review the utility's filing and submit a report to the Commission containing a recommendation concerning the reasonableness of the annual update. The Commission then must decide if it will "…accept the annual update or direct the electrical utility to make changes to the annual update that the commission determines to be in the public interest."[18]

Commission Consideration of DESC IRP

It should be noted that there is a fundamental difference between the statutory requirements and the Company's request in this proceeding. The statute directs the Commission to approve the IRP if it finds that the IRP "represents the most reasonable and prudent means of meeting the electrical utility's energy and capacity needs at of the time the plan is reviewed."

However, the Company requests that the Commission approve the IRP if it finds the RPs in the IRP provide a "reasonable range of options" that reasonably balance the statutory factors.

> DESC is asking the Commission to determine that, as a whole, the eight (8) resource plans reasonably balance the relevant statutory factors and provide a reasonable range of options for future evaluation. Based on such a

[18] S.C. Code Ann. § 58-37-40(D)(2).

determination, DESC respectfully requests that the 2020 IRP be approved as submitted.[19]

ORS Approach to Performing this Review

ORS set objectives for the review, analyses and recommendation to determine if the Company met the statutory requirements of Section 40 and to provide a recommendation to approve, modify or reject the Company's IRP. To achieve these objectives, ORS reviewed the Company's IRP, testimony, and consultant report, reviewed prior DESC IRPs and IRPs filed by other electric utilities, including Duke Energy Carolinas, LLC and Duke Energy Progress, LLC (together, "Duke Energy"), Georgia Power Company, Entergy Louisiana, LLC, PacifiCorp, Kentucky Power Company, and others. ORS also conducted extensive discovery, including eight (8) sets with over 121 questions including multi-part questions, held a technical conference call with the Company on June 23, 2020, and submitted informal questions that required DESC subject matter experts to review nd respond.

Compliance with Requirements of Section 40

This section of the Report first addresses the Company's compliance with the specific information requirements listed in the statute and then addresses the seven (7) factors that the Commission is directed to consider in making a determination of whether the Company's "proposed integrated resource plan represents the most reasonable and prudent means of meeting the electrical utility's energy and capacity needs as of the time the plan is reviewed."[20]

To ensure the Commission has the necessary information to make this determination, the Company is required to provide the following specific information in its IRP.[21] In most instances, the Company provided the required information; however, this must be tempered by the fact that certain information was inadequate or erroneous, or there were other concerns that are identified and described in subsequent sections of this report.

Statutory Requirements in Section 40(B)(1) and (2)

The following section of this Report provides the ORS assessment of the Company's compliance with the Section 40(B)(1) and (2) statutory requirements.

[19] Direct Testimony of Eric H. Bell, June 4, 2020, pg. 29, ln. 15.
[20] Section 40(C)(1) sets forth the standard of review and Section 40(C)(2) sets forth the factors.
[21] Sections 40(B)(1) and (2).

B: An integrated resource plan shall include:

(1)(a): a long-term forecast of the utility's sales and peak demand under various reasonable scenarios.

The IRP complies with the requirement to provide a long-term forecast of its sales and peak demand, and provides such forecasts under various scenarios that generally were found to be reasonable. However, ORS identified concerns that should be addressed in future IRPs. These concerns are addressed in the subsequent section on Load Forecasting. Due to the fact that the Company is not expected to make any major resource decisions in the near future; likely not until 2035, or possibly 2028 at the earliest, these concerns do not adversely affect any actual resource decisions.

(1)(b): the type of generation technology proposed for a generation facility contained in the plan and the proposed capacity of the generation facility, including fuel cost sensitivities under various reasonable scenarios.

The IRP complies with the requirement to provide this information, although ORS identified concerns with the information that impinge on the assessment of reasonableness. These concerns are addressed in subsequent sections of this report. The Company identified potential new generic resources based on various technologies, including CC, ICT (standard and aeroderivative), owned solar, owned BESS, and solar and battery power purchase agreements ("PPA"). It developed capacity and operating profiles for each new generic resource for use in the PROSYM production cost modeling and in the Excel workbook revenue requirement modeling. The Company developed eight (8) RPs that reflect different combinations of potential retirements of existing resources and potential additions of the new generic resources. It also developed five (5) Intervenor RPs that reflected alternative assumptions specified by the Intervenors. Furthermore, it considered natural gas fuel cost sensitivities, including low gas, base gas, and high gas sensitivities that relied on data from NYMEX and the Energy Information Administration ("EIA"), and it considered $0/ton and $25/ton carbon tax scenarios.

(1)(c): projected energy purchased or produced by the utility from a renewable energy resource.

The IRP complies with this requirement, although ORS identified concerns with the information that impinge on the assessment of reasonableness, which are addressed in subsequent sections of this report. The Company included existing and new renewable resources in the form of hydro, solar PPAs, owned solar, and BESS resources in different combinations in the various RPs and it identified the amount of renewable energy that each RP would produce.[22]

(1)(d): a summary of the electrical transmission investments planned by the utility.

The IRP complies with this requirement. The Company provided a summary of its transmission planning process and identified and described its planned future investments based on its most recent transmission assessment studies. The Company also incorporated the cost of the incremental transmission investments, including interconnection costs, necessary to integrate each potential new resource addition.

(1)(e): several resource portfolios developed with the purpose of fairly evaluating the range of demand-side, supply-side, storage, and other technologies and services available to meet the utility's service obligations. Such portfolios and evaluations must include an evaluation of low, medium, and high cases for the adoption of renewable energy and cogeneration, energy efficiency, and demand response measures, including consideration of the following:

- **i. customer energy efficiency and demand response programs;**
- **ii. facility retirement assumptions; and**
- **iii. sensitivity analyses related to fuel costs, environmental regulations, and other uncertainties or risks.**

The IRP generally complies with this requirement, although ORS identified concerns with the information that impinge on the assessment of reasonableness of the resource portfolios and facility retirement assumptions, among other issues and identified information that was missing from the filing. These concerns are addressed in subsequent sections of this report.

The Company developed eight (8) specific RPs to evaluate DSM effects on peak loads and supply-side resources, including BESS resources. For DSM, including energy efficiency and demand response ("DR") programs, the Company developed three (3) sensitivities with which to study these supply side resource plans. These DSM sensitivities were created by adjusting the baseline peak load forecast for high/medium/low energy efficiency programs to calculate a net peak load for each case and high/medium/low DR programs to determine dispatchable demand resources.

[22] IRP Report at 49.

While limited, the Company did include RPs that consider coal and natural gas resource retirements, and the Company performed an additional set of retirement analyses due to the major outage at the Wateree 2 unit that considered repair or replacement of damaged components or retirement of the resource.

The Company performed sensitivity analyses over a range of natural gas prices and sensitivities that assumed a $25 per ton carbon tax as a proxy for the cost of potential new environmental regulations. The Company considered natural gas fuel cost sensitivities, including low gas, base gas, and high gas sensitivities that relied on data from NYMEX and the Energy Information Administration EIA. The environmental sensitivities assumed that the $25 per ton carbon tax would begin in 2025 and then escalate by 2% annually thereafter.

However, the costs for all resource plans under the Low and High DSM sensitivities, with the $25/ton CO_2, and low and high gas sensitivities are missing from the IRP report.

(1)(f): data regarding the utility's current generation portfolio, including the age, licensing status, and remaining estimated life of operation for each facility in the portfolio.

The IRP complies with this requirement. The Company provided a description of the existing resources and the required information to determine the age of the units, licensing status of its hydro and nuclear resources, and the remaining estimated life of operation for each resource.[23] ORS has concerns with the Company's reliance on a six (6) year old depreciation study for the remaining estimated life of operation for each facility and the Company's failure to perform economic studies to assess when the facilities in the existing generation portfolio should be retired. These concerns are addressed in subsequent sections of this report.

(1)(g): plans for meeting current and future capacity needs with the cost estimates for all proposed resource portfolios in the plan.

The IRP complies with the requirement to include plans and cost estimates for all potential new resource additions.[24] However, ORS has identified concerns with the Company's selection of plans and its cost estimates that impinge on the reasonableness of the plans, cost estimates, and ranking of the plans. These concerns are addressed in subsequent sections of this report.

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[23] IRP Report at 33.
[24] *Id.* Cost estimates may be found in the table at 39 and the RPs are discussed at 40.

B(1)(h): an analysis of the cost and reliability impacts of all reasonable options available to meet projected energy and capacity needs.

The IRP complies with the requirement to include an analysis of all options by performing PROSYM production cost modeling analysis, although ORS identified concerns with the information that impinge on the assessment of reasonableness. These concerns are addressed in subsequent sections of this report. PROSYM evaluates the amount of energy unserved and assigns a cost to that for each RP evaluated. In addition, the Company presents its Reserve Margin policy and uses that policy to determine its need for capacity to meet reliability requirements.

(1)(i): a forecast of the utility's peak demand, details regarding the amount of peak demand reduction the utility expects to achieve, and the actions the utility proposes to take in order to achieve that peak demand reduction.

The IRP complies with the requirement to provide a foreast of its peak demand, and it provided details regarding the amount of peak demand reduction the Company expects to achieve. The Company provided a list and description of its energy efficiency, energy conservation, and load management programs that are or will be in effect during the planning period and how these programs will reduce or shift customer demand and energy usage. The Company provided a forecast of its peak demand under low, medium, and high DSM sensitivities.

(B)(2): An integrated resource plan may include distribution resource plans or integrated system operations plans.

The IRP complies with this optional requirement. The Company provided a brief discussion of how it is introducing advanced metering infrastructure ("AMI") and distribution automation in its system in the DESC IRP.

Statutory Requirements in Section 40(C)(2)

After its review of the "evidence concerning the integrated resource plan, including the reasonableness and prudence of the plan and alternatives to the plan," the statute directs the Commission to consider seven (7) factors in making its determination as to whether the IRP "represents the most reasonable and prudent means of meeting the electrical utility's energy and capacity needs at of the time the plan is reviewed." The following section addresses each of these seven (7) factors.

C(2): The commission, in its discretion, shall consider whether the plan appropriately balances the following factors:

(a) resource adequacy and capacity to serve anticipated peak electrical load, and applicable planning reserve margins.

All RPs presented in the IRP, including the RPs performed using assumptions provided by the SCSBA, ostensibly provide adequate resources and capacity to serve the anticipated peak electrical load and meet applicable planning reserve margins, except for the RPs that include new BESS resource additions. The Company assumed that BESS units would have 10-year operating lives, which was properly reflected in the capital cost revenue requirement analysis; however, in the expansion plan development process and in the production cost modeling, the Company erroneously assumed that new BESS resource additions could operate well beyond their operating lives. The RPs that include BESS resource additions do not ensure adequate resources and capacity.

(**b) consumer affordability and least cost.**

The Company does not explicitly identify which RP it intends to act upon in its IRP but asserts that "Since RP2 is the least cost alternative under zero cost CO_2, Base Gas, and Medium DSM, it is considered the base case."[25] In his direct testimony, Company witness Eric Bell states "Under those assumptions, and across the greatest number of other sensitivity analyses, Resource Plan 2 is the low-cost alternative for customers and therefore is the preferred plan."[26] The Company ranked each RP by cost, using a levelized net present value metric, and by CO_2 emissions, using a tons emitted metric.

The Company asserts that RP2 is the least cost RP and RP8 is the lowest CO_2 emissions RP in the IRP. However, a different RP2, based on assumptions provided by the SCSBA (Appendix A to the IRP Report), is lower cost than RP2 in the IRP with the base gas price and $0 per ton CO_2 sensitivities. The Company's stated reason for not accepting this RP2 based on assumptions provided by the SCSBA as the least cost case is that "[SBA] Resource Plans 2 through 4 assumed a level of DSM that is not cost effective." ORS notes that this RP also suffers from other more significant infirmities, also reflected in certain RPs included in the IRP, that the new BESS resource additions will operate well beyond their operating lives, are never retired or replaced, and will incur no annual O&M expense or capital expenditures/plant additions. These problems are magnified in the SCSBA RPs because of the greater number of new BESS resource additions compared to the RPs in the IRP.

In addition, in conjunction with the recent repair/replace/retirement analyses that the

[25] IRP Report at 46.
[26] See Direct Testimony of Eric Bell, pg. 25, at ln. 19.

Company conducted, it revised its IRP assumptions to include updated coal and oil prices and to include fixed transportation costs for its new ICT resource additions. As a result of these subsequent analyses, the case the Company referred to as the "Replace 2" RP in these subsequent studies is lower in cost than the RP2 case that was presented in the IRP. In the Replace 2 case, Wateree 2 is repaired and restored to service in April 2022, and both Wateree units continue to operate until 2044, the probable retirement date for those units. In the Replace 2 case, the Company adds a new CC resource in 2035 instead of the new ICT that it adds in 2035 in the RP2 case in the IRP.

ORS cannot conclude that RP2 or any other RP in the IRP, including the plans developed using assumptions provided by the SCSBA, or any RP subsequently developed, is the least cost RP. ORS concludes that the results of all of the RPs are unreliable due to the numerous errors that have been identified that affect the modeling and the metrics used to evaluate and rank the RPs.

ORS recommends the RPs presented in the IRP be modified in order to correct the multiple errors identified in the list of recommendations above and to accurately determine the least cost RP and consumer affordability of the RPs, as measured by the annual levelized net present value of each RP.

(c) compliance with applicable state and federal environmental regulations.

ORS concludes all RPs presented in the IRP and developed using assumptions provided by the SCSBA comply, or will comply, with applicable state and federal environmental regulations. The Company correctly assumed that it would incur capital expenditures/plant additions by 2028 at the Wateree and Williams coal-fired plants to comply with state and federal environmental regulations, including the ELG rule adopted by the Environmental Protection Agency ("EPA") in 2015, and which are currently under review. The Company has addressed the risk of CO_2 regulations, though much uncertainty exists as to what state requirements will ultimately be implemented and whether the EPA's Affordable Clean Energy ("ACE") Plan will remain in effect or will be replaced by a different administration depending on the outcome of the upcoming election.

(d) power supply reliability.

ORS concludes, for most of the RPs evaluated, the Company has planned for an adequate level of reliability. However, as noted previously, the RPs that incorporate BESS resource additions (RP5, RP7 and RP8) do not include sufficient new resource additions necessary to replace the BESS resources at the end of their operating lives.

In addition, ORS identified and recommends process modifications to improve upon the Company's reserve margin policy and its methodology used to evaluate the reliability of its system. Although there are concerns with some aspects of the Company's reserve margin methodology, DESC's planning reserve margin requirements do not appear to be out of line with other regional utilities. Moreover, because the Company does not need to add new resources until 2035, or possibly until 2028 if it retires the Wateree plant, DESC will have an opportunity to address the concerns identified by ORS in a future IRP update or comprehensive IRP. This is discussed in greater detail in the Reserve Margin section of this report.

(e) commodity price risks.

ORS concludes the RPs in the DESC IRP adequately consider commodity price risks through the consideration of natural gas and CO_2 price sensitivity cases. The primary commodity price risks are for natural gas-fired new CC and ICT resource additions, assuming there are no early retirements of the existing coal-fired and natural gas-fired resources. Commodity price risks that impact gas-fired resources are mitigated in the RPs that reflect more renewable resources, however, the reduction in commodity price risk must be balanced against concerns about customer affordability, integration, and reliability impacts associated with those types of resource additions.

(f) diversity of generation supply.

ORS concludes that the existing resource mix reflects diversity in the fuel source, type, and location of those resources. The existing resource mix includes coal-fired, natural gas-fired, hydro, pump storage, nuclear, and solar resources. ORS also concludes that the new resource additions reflected in the eight (8) RPs in the IRP maintain this diversity by considering additional natural gas-fired CC and ICT resources, solar PPA resources, owned solar resources, BESS resources and short-term capacity purchases. The RPs developed using assumptions provided by the SCSBA include significantly more solar and BESS resources offset by fewer new natural gas-fired CC and ICT resources. While this will reduce commodity price risk and CO_2 production, it will also introduce concerns about customer affordability, integration, and reliability impacts that must be considered. For example, RP2, RP4, and RP5 of the SCSBA RPs reflect a generation mix consisting of 25% or more BESS capacity by 2049. This provides a high level of exposure given the operating limitations of the BESS capacity both for capacity and energy purposes.

(g) other foreseeable conditions that the commission determines to be for the public interest.

The Company analyzed CO_2 taxes, which can serve as a proxy for potential future environmental regulations regarding CO_2 emissions. All RPs analyze this possibility, though the plan that reduces this risk exposure the most is the SCSBA RP3. However, the RPs based on assumptions provided by the SCSBA, including SCSBA RP3, are even more unreliable than the Company's RPs due to the Company's modeling errors that significantly understate the costs of new BESS resource additions.

In addition, the Company should create a stakeholder process to provide opportunities for stakeholder involvement and input in the formulation of future IRPs. The Company should develop a 3-year action plan that identifies all actions the Company intends to take in order to implement its IRP. Each of these items is discussed in greater detail in the Other Considerations section of this report.

Evaluation of DESC's IRP

Load and Energy Forecast

This section reviews the Company's 2020 IRP load (peak demand) and energy forecasts. As discussed below, ORS determined that the forecasts are reasonable, but has identified a number of concerns that should be addressed in future IRPs. These findings focus primarily on methodological issues, but because the Company is not expected to make any major resource decisions to add new resources before 2035, or 2028 at the earliest, other than deciding what to do about Wateree 2, these issues do not adversely impact the conclusion that the load and energy forecasts are reasonable at this time.

DESC's load and energy forecast reported in the IRP report covers the 15-year period 2020 through 2034. The Company's energy forecast assumes a 15-year average annual growth rate of 0.5% and is derived based on a set of econometric models that forecast average energy use per customer and the number of customers for both the residential and commercial classes, as well as total energy usage for industrial classes.

The Company's peak load forecast assumes an average annual growth rate of 0.7% over the 15-year forecast period. The peak load forecast is developed for the residential and commercial classes using adjusted class load research data and the number of customers. For the industrial class, the peak load forecast is based on class load data in the form of a summer and winter "peak kW per average kW" ratio applied to the corresponding energy forecast for the class.

For compliance with Section 40, paragraph B1a, which requires the utility to develop "a long-term forecast of the utility's sales and peak demand under various reasonable scenarios,"[27] the Company developed a base forecast, which it also refers to as a medium forecast, as well as high and low forecasts. The Company refers to these three (3) forecasts as its "economic scenarios." It is important to point out that the Company never actually evaluated any alternative resource plans or conducted any economic analyses with those scenarios, which is highly unusual in an IRP evaluation. As will be discussed further below in the DSM section, the Company did conduct alternative load scenarios, again not using these high and low demand and energy forecasts, but using load forecasts derived by applying high and low DSM adjustments to its base load forecast, which the Company seems to accept as being a reasonable means of deriving load growth sensitivity cases.

To avoid confusion between these different load forecasts, the low, medium and high load forecasts that the Company developed to comply with Section 40(B)(1)(a) will continue to be referred to as the economic scenario load forecasts, and the load forecasts that it derived by applying DSM adjustments and that were actually used to perform economic analyses will be referred to as the DSM derived load forecasts.

The following discusses the ORS review of the Company's base case (medium) economic load forecast, and covers the following topics:

1. Review of the load forecasting methodologies;
2. Review of the model results; and,
3. Analysis of the performance of the load forecasts.

Before discussing the Company's load and energy forecast, it is important to note that the IRP Report only discussed the forecast results, but did not provide any detailed information or description of its load and energy forecast methodology. In response to discovery, DESC provided a fourteen (14) page document describing the methodology in somewhat more detail.[28] However, six (6) pages were devoted to describing how short term forecasts, which were not used in long term IRP analyses, were developed. More importantly, the description of the summer and winter peak load forecast methodology consisted of less than half a page of text as follows:

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[27] S.C. Code Ann. § 58-37-40(B)(1)(a)
[28] ORS AIR 1-1(c)

> **Peak Demand Forecast**
> A demand forecast is made for the summer peak, the winter peak and then for each of the remaining ten (10) months of the year. The summer peak demand forecast, and the winter peak demand forecast is made for each of the six (6) major classes of customers. Customer load research data is summarized for each of these major customer classes to derive load characteristics that are combined with the energy forecast to produce the projection of future peak demands on the system. Interruptible loads and standby generator capacity are captured and used in the peak forecast to develop a firm level of demand. By utility convention the winter season follows the summer season. The territorial peak demands in the other ten (10) months are projected based on historical ratios by season. The months of May through October are grouped as the summer season and projected based on the average historical ratio to the summer peak demand. The other months of the year are similarly projected with reference to the winter peak demand.

When asked for a detailed description of the methodology in a follow-up discovery request, the Company responded that such a description was provided in the testimony of Joseph Lynch in a 2019 proceeding and that ORS received a copy of that testimony.[29]

IRP reports typically provide a more thorough presentation of the load and energy forecasting methodology, and this should be provided in all future IRP Reports, including annual IRP updates, and could be included in the reports in an appendix. Information provided should include detailed descriptions of the methodology, the specific models used to develop the various rate class and peak demand forecasts (i.e., the model specifications, statistical results), detailed forecast results for each rate class, a discussion of driving assumptions (e.g., economic and demographic projections used to produce the forecast), a discussion of the load research sampling studies undertaken by the Company to supply data for the individual rate class peak demand forecasts, and other details of the Company's forecasting process. While the Company does present more detailed information as exhibits to Dr. Lynch's testimony,[30] the detailed support for the load and energy forecasts should be presented as part of the IRP report itself.

The Company's energy forecasts appear to have been developed using a reasonable methodology based on an econometric model that relied on the key drivers of weather,

[29] ORS AIR 2-3.
[30] Attachment JML-1, "Energy Forecast Documentation", at pg. 15, and JML-2, "The Peak Demand Forecast for 2020.

economic activity (income, industrial production) and, for the residential and commercial classes, per customer forecasts and population as the demographic variable. For the industrial class, the long term energy forecast was based on total energy usage (not average use per customer). The statistical model results, which were based on historic annual data over the periods of 1985-2018 for the residential average use models, and 2001-2018 for most of the commercial and industrial models, indicated a reasonable level of statistical robustness in the form of goodness of fit (R^2) and coefficient t-statistics. The basic Rate 10 Residential class average use per customer model is shown in Table 1 below. The Company's models utilize a fairly typical estimation approach by using a log normal specification, in which each of the independent and dependent variables are transformed to their natural log equivalents.

Table 1

Residential Class 10 Average Use Per Customer Model

Variable	Estimate	t-Value	Pr > [t]
Intercept	0.75018	0.88	0.3877
LRPCI	0.29011	10.26	<.0001
LHDD	0.12019	3.18	0.0036
LCDD	0.29721	5.09	<.0001
LPRICE	-0.07147	-1.04	0.3064
LHIGH	-0.00868	-7.52	<.0001
R-Square	0.8615		
Adj R-Square	0.8367		

As can be seen, the coefficients under the heading Variable, are statistically significant at a 90% confidence level or above, except for the price of electricity (LPRICE is only significant at a 70% confidence level). The most significant variable is LRPCI (log of real personal income per capita). Per capita income has been shown over many years to drive consumption, including electric usage. The higher the level of per capita income, the greater the number of appliances and the ability of consumers to utilize those appliances. This is not surprising in an annual model of average use per customer estimated over a period of thirty-four (34) years. The R-Square value of the residential average use model is 0.8615, which indicates that about 86% of the variation in average use during the period of 1985 to 2018 is explained by the model. For the most part, other rate classes showed similar results compared to those for the Residential Class 10 presented above.

Unlike other electric utilities, DESC does not attempt to model appliance usage directly, which means that changes in appliance energy efficiency and other energy efficiency changes that have been rapidly occurring during the past ten (10) or more years must be factored into the DESC residential and commercial forecasts as after the fact adjustments. Other utilities, such as Louisville Gas and Electric Company and Kentucky Utilities Company, with a combined 6,700 MW peak load (versus 5,000 MW for DESC), use a Statistically Adjusted End Use ("SAE") model to forecast residential and commercial energy usage. This type of model incorporates very detailed information about the composition of end uses that form the basis for average usage per customer. For the industrial class energy use forecast, Louisville Gas and Electric Company and Kentucky Utilities Company employ an econometric approach similar to the DESC methodology.

Georgia Power Company also uses an end use approach. Georgia Power Company's residential model includes forecasts of twenty-two (22) major household uses, segmented by housing type. Georgia Power Company uses similar end-use approaches to model the commercial and industrial sectors. For example, its commercial model considers thierteen (13) different commercial building types (e.g., warehouse, office building, restaurant, healthcare facility), and ten (10) end-uses for each building type. On the other hand, Florida Power and Light Company's residential model is similar to DESC's in that it is derived based on a use per customer model and a separate customer model. The use per customer model is an econometric model driven by weather, personal income and electric price.

DESC's peak load forecast does not rely on any independent modeling of residential, commercial or industrial load (i.e., the peak load forecast is tied to one (1) or more components of the corresponding class energy forecast). Instead, the residential and commercial peak demand growth is strictly driven by projected customer growth. For the residential and commercial rate classes, the Company calculates an average kiloWatt ("kW") use per customer value for both the summer and winter peak periods using load research sampled data and multiplies these kW per customer amounts by the forecasted number of customers for these classes. The kW peak demand values per customer are assumed to be fixed for each of the next fifteen (15) years. Thus, as mentioned, the residential and commercial peak demand forecasts are strictly driven by projected customer growth. While the Company does make a small adjustment each year for federally mandated appliance and lighting efficiency changes, there is no effect for customer behavioral changes that might occur over the next fifteen (15) years. This can be seen clearly in Figures 1 and 2 below for the residential class. Moreover, the residential class summer and winter peak load forecast growth rates are basically identical.

Figure 1

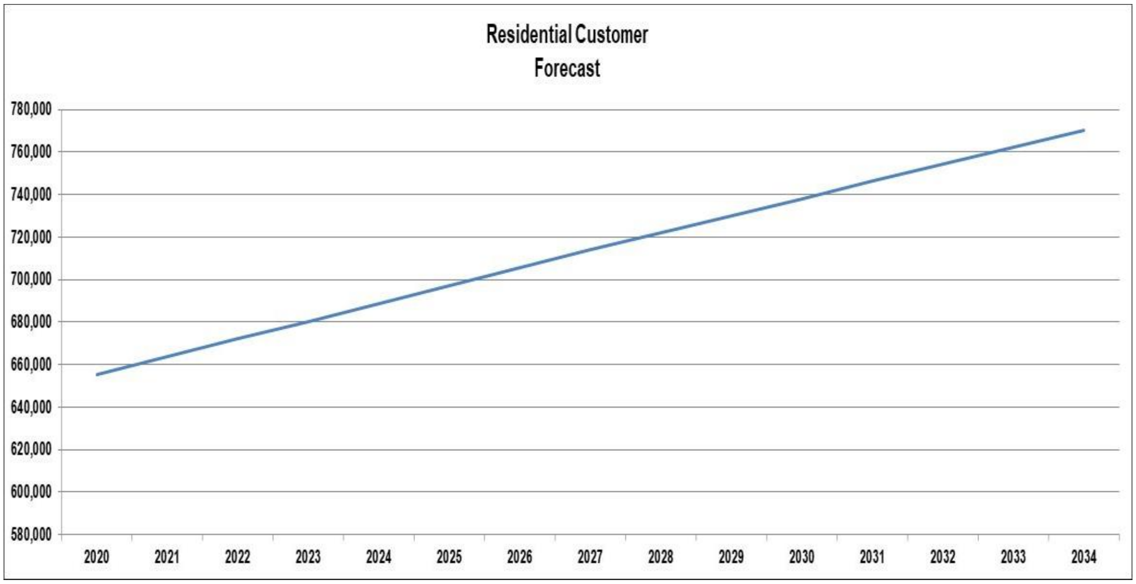
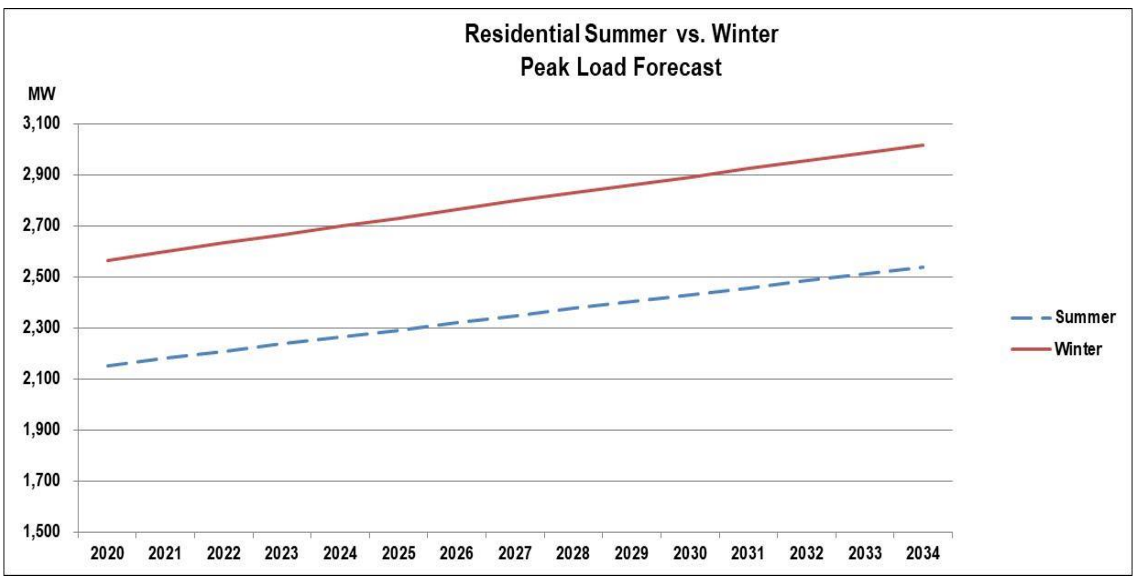


Figure 2



For the commercial class, the summer and winter peak load forecasts are driven entirely by the number of commercial customers, as the Company makes no efficiency adjustment as it makes for the residential class. This is the case despite the fact that the

Company's commercial energy forecast projects commercial energy use per customer will continue to decline over the next fifteen (15) years. At page six (6) of his direct testimony in this case, Dr. Lynch states: "The average use per customer in the commercial class is projected to continue decreasing, but this is a function of the mix of customers." Figures 3 and 4 below show the commercial customer forecast and the corresponding summer/winter commercial peak load forecast.

Figure 3

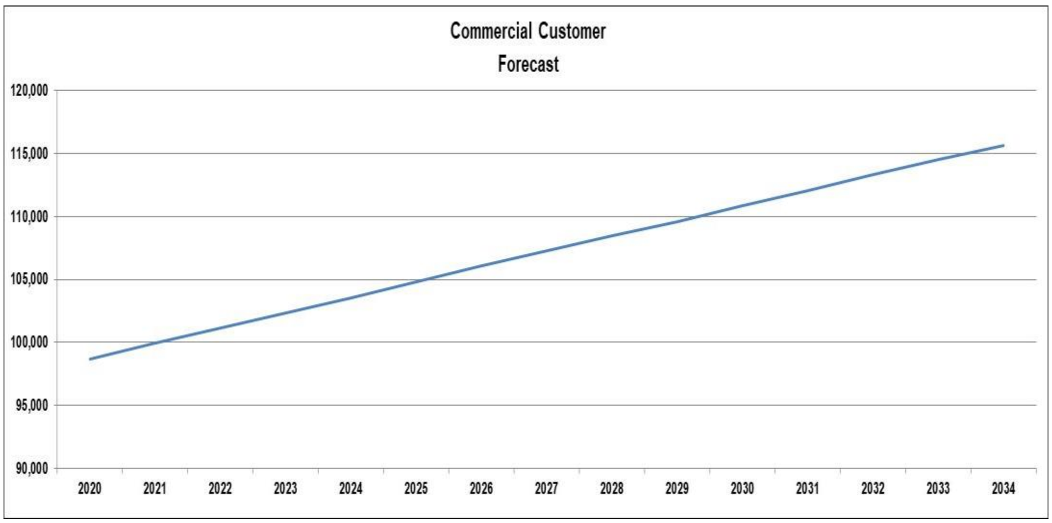
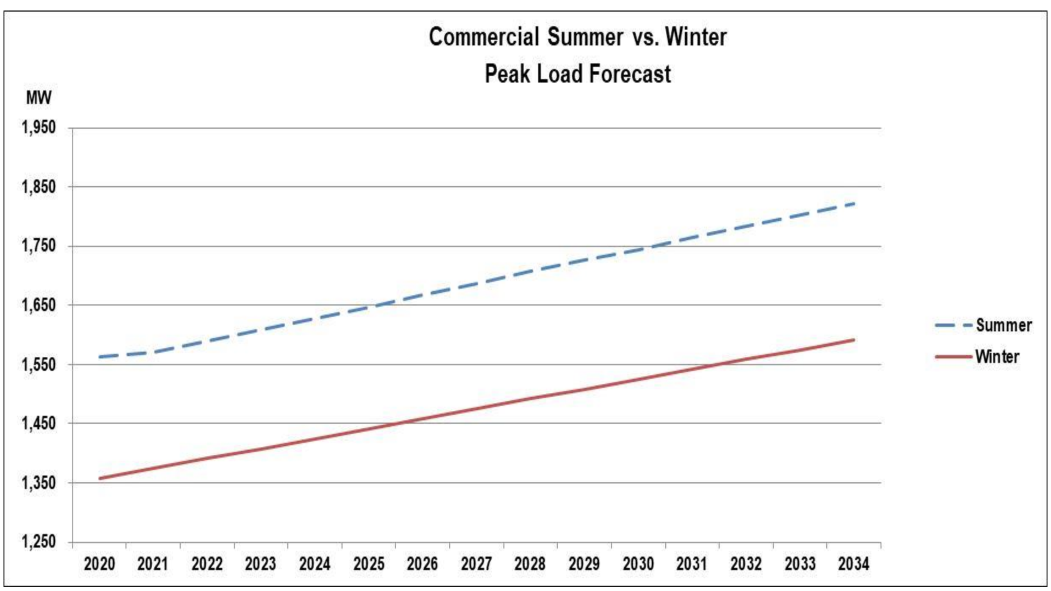


Figure 4



The forecast assumes that average summer and winter peak demand per commercial customer remains constant for the next fifteen (15) years, despite the fact that historically, this metric has actually dropped by 11% in the summer and 3% in the winter over the past ten (10) to twelve (12) years.[31]

The Company's residential and commercial peak load forecasts, which are based on the product of the number of residential and commercial customers and an average summer and winter peak kW per customer value, comprise approximately 80% of the system winter peak load and 77% of the system summer peak load in 2020. These peak load forecasts are derived based on an average kW per customer peak demand value that remains fixed for each of the next fifteen (15) years. Therefore, DESC's system load growth projection is mostly driven by the Company's forecast of the number of customers on its system. Other than a small adjustment to the residential peak load forecast to account for federally mandated appliance efficiency changes, 80% of the peak forecast is a function of only the number of residential and commercial customers expected over the next fifteen (15) years. DESC should seek to improve its residential and commercial peak load forecasts to reflect the type of behavioral factors that are likely to impact peak demand over time, such as changes in appliance saturation and appliance efficiency improvements, other than caused exclusively by federally mandated requirements. This could include more detailed time series modeling of historic load research data that would permit a forecast of average summer and winter residential and commercial peak load, rather than assuming a constant value over the 15-year forecast horizon.

For the industrial class, the Company's summer and winter peak load forecast is driven by the corresponding industrial class energy forecast. The peak forecast is developed by applying a peak kW per average demand factor to the energy forecast. This is essentially a load factor approach that captures forecasted changes in industrial energy usage directly in the peak load forecast, in contrast to the residential and commercial forecasts that are driven only by customer growth. Because the industrial class peak load forecast is driven by the industrial energy forecast, the fundamental factors modeled by the Company in its industrial class energy models are implicitly considered in the industrial class peak load forecast. This is a reasonable approach and provides a consistent methodology to both the industrial class energy and peak load forecasts.

As discussed in the Company's IRP report and in Dr. Lynch's testimony, DESC is projecting that it will continue to be a winter peaking company over the next fifteen (15) years, driven by growth in the residential class winter peak, relative to the summer peak.

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[31] See Direct Testimony of Joseph Lynch at page 12.

The commercial and industrial classes continue to be summer peaking. The other classes (e.g., wholesale), which are also winter peaking in the aggregate, comprise only 6% of peak load in 2020 and only 2% by 2034. Though the Company's methodology does not assume any specific growth per customer in residential winter peak load, the fact that the winter and summer forecasts are driven only by customer growth arithmetically results in a continuation of the relative growth of the winter peak. This is because the most recent load research data shows that the average winter peak load per residential customer is currently 19% greater than the average summer peak load per customer.

As can be seen in the table below, the excess of the winter peak residential load over the residential class summer system peak is forecasted to grow from 413 MW in 2020 to 474 MW in 2034. At the same time, the total winter system peak excess over the summer system peak only grows from 75 MW in 2020 to 119 MW in 2034. The residential class is clearly driving the Company's winter peak load dominance. A small additional amount of winter residential DR, or energy efficiency could possibly reposition the Company back to being a summer peaking utility. Alternatively, if the residential class average winter peak kW per customer were to decline by the same rate of decline (5%) as has occurred over the past eleven (11) years, the system would revert to a summer peaking system by 2029, assuming no change in the residential class average summer peak kW per customer. While there is no specific reason to expect such an outcome, the fact that the difference between the summer and winter system peaks is relatively small (a 1.6% difference in 2020, a 2.2% difference in 2034), suggests that there is likely an opportunity for a shift to occur over the next fifteen (15) years with additional winter residential DSM. This outcome was also discussed and confirmed by Dr. Lynch is his testimony in Docket No. 2019-184-E on page 16.

Table 2

Excess Winter Peak Load vs. Summer Peak Load : System Compared to Residential Class

Year	Residential Winter Peak Forecast (MW)	Residential Peak Forecast Summer	Excess Residential Winter Peak vs. Summer Peak	Excess System Winter Peak vs. Summer Peak	Excess Non-Residential Summer Peak vs. Winter Peak
2020	2,551	2,138	413	75	338
2021	2,583	2,167	416	77	339
2022	2,614	2,194	420	76	344
2023	2,626	2,220	407	58	348
2024	2,655	2,229	426	76	350
2025	2,684	2,253	431	81	350
2026	2,713	2,278	435	84	351
2027	2,740	2,301	439	84	356
2028	2,768	2,325	443	82	361
2029	2,795	2,347	448	111	337
2030	2,827	2,370	457	119	338
2031	2,858	2,397	461	120	342
2032	2,889	2,423	466	118	348
2033	2,919	2,449	470	119	351
2034	2,949	2,475	474	119	356

In fact, in 2019, the Company experienced a significant summer system peak that exceeded its winter peak. The 2019 summer peak of 4,714 MW occurred in July of 2019, while the subsequent winter system peak, which occurred in January of 2020, was only 4,087 MW. This is a significant reversal from recent experience, and is not consistent with the Company's expectations, as shown in its IRP load forecast.

Finally, as mentioned above, in order to comply with Section 40(B)(1)(a), the Company also developed high and low load and energy forecasts. Rather than deriving forecasts based on econometric models, using high and low economic drivers (for example, a high and low assumed income growth rate, compared to the base case assumption), the Company simply created high and low energy forecasts based on DESC's determination "that reasonable bounds on the risk of change in the load growth forecast are a high of 1.7% and a low of 0.25%, per year as compared to the 0.5% growth projection for energy in the accepted forecast."[32]

The Company provided no discussion in either its IRP Report or any witness testimony that explained how the high and low peak load forecasts were developed, which again were characterized by the Company as being alternative economic scenarios. Based on a review of Excel spreadsheet formulas, the Company developed its high and low

[32] Direct Testimony of Joseph Lynch at page 13.

summer and winter peak load economic forecast scenarios by applying a ratio (peak load/energy) to the incremental or decremental energy forecast each year to produce a corresponding high incremental peak forecast or low incremental peak forecast.[33] As a result of the DESC methodology, the growth rates for the high and low summer and winter peak load forecasts (economic scenarios) are not identical to the assumed 0.25% low growth energy forecast and the 1.7% high growth energy forecast, even though they are a direct calculation from the high and low energy forecasts.

It is also important to point out that the high and low peak load forecast scenarios that were used in the Company's IRP planning analyses are not these high and low energy and peak load forecasts. The economic scenario forecasts were only included for reporting purposes in the table on page 11 of the IRP Report.[34] Table 3 shows another summary of the economic scenario peak demand forecasts.

Table 3
Economic Scenario Peak Forecasts (MW)

Year	Summer			Winter		
	Low	**Medium**	**High**	**Low**	**Medium**	**High**
2020	4,816	4,816	4,816	4,891	4,891	4,891
2021	4,837	4,847	4,907	4,914	4,924	4,985
2022	4,858	4,879	5,000	4,934	4,955	5,078
2023	4,875	4,905	5,089	4,933	4,964	5,150
2024	4,876	4,916	5,164	4,951	4,992	5,244
2025	4,890	4,941	5,254	4,970	5,022	5,340
2026	4,905	4,967	5,347	4,988	5,050	5,437
2027	4,921	4,993	5,441	5,004	5,077	5,533
2028	4,937	5,019	5,538	5,018	5,102	5,629
2029	4,948	5,041	5,631	5,057	5,152	5,754
2030	4,986	5,090	5,756	5,102	5,209	5,890
2031	5,030	5,146	5,891	5,147	5,266	6,028
2032	5,074	5,201	6,028	5,188	5,319	6,164
2033	5,117	5,256	6,167	5,232	5,375	6,306
2034	5,157	5,309	6,306	5,273	5,428	6,447
CAGR	0.49%	0.70%	1.94%	0.54%	0.75%	1.99%

[33] The incremental or decremental energy forecast value is the difference between the medium forecast and the high energy forecast (incremental) and low energy forecast (decremental).

[34] Note that the table on page 11 seems to be mislabeled. The discussion preceding the table indicates the forecasts relates to high and low peak demand and energy projections, however, the table states the forecasts relate to high and low DSM impacts. This should be clarified.

These load forecasts represent a wide range of growth rates, as seen by the compound average growth rate ("CAGR") calculation on the last row of the table.

As mentioned already, these forecasts were not used for the purpose of evaluating the impact of alternative energy and peak load forecasts on resource expansion plans, which in fact is the principle objective of an IRP study. Instead, the Company only considered the impact of high and low DSM assumptions as an adjustment to its medium load and energy forecast. The peak forecasts that were integrated into resource planning were provided to ORS Staff through responses to discovery.[35] These load forecasts were developed based on estimates of low, medium and high DSM forecasts.

Additional discussion of these DSM estimates is included in the DSM section below. However, to illustrate how the Company adjusted its base forecast to develop the low, medium and high peak load forecasts used for IRP economic analyses, Table 4 is provided, which summarizes the calculations for 2034 as an illustrative example.

Table 4

Comparison of DESC Low, Medium and High Winter Peak Forecasts - 2034

Low		**Medium**		**High**	
Base Forecast	5627	Base Forecast	5627	Base Forecast	5627
Existing DR	-237	Existing DR	-237	Existing DR	-237
Subtotal	5390	Subtotal	5390	Subtotal	5390
EE	-306.4	EE	-199.3	EE	-102.8
Subtotal	5083.6	Subtotal	5190.7	Subtotal	5287.2
New DR	-149.6	New DR	-43.4	New DR	0.0
Total	**4934.1**	**Total**	**5147.3**	**Total**	**5287.2**
Peak W/O DR	**5320.6**	**Peak W/O DR**	**5427.7**	**Peak W/O DR**	**5524.2**

*The low and high peak forecasts correspond respectively to high DSM (EE + new DR) and low DSM.

The base forecast for each of the three (3) peak load scenarios is identical since the Company uses the same underlying economic scenario (the base case scenario) for all three (3) forecasts (low, medium, high). The Company developed these forecasts starting

[35] ORS AIR 1-1b.

with a baseline load forecast and then subtracted the respective high, moderate, or low impacts of energy efficiency. As shown, the load impact of existing DR is treated as an adjustment to the base load forecast. For purposes of capacity planning and for production cost modeling, the existing DR and any new DR are modeled as capacity resources rather than adjustments to load, so DR MWs are added back to the load forecast to get the final planning load assumption.

Table 5 compares the compound average growth rates from 2020 – 2034 for the load forecasts that the Company developed and simply reported in the table on page 11 of the IRP report ("economic scenarios"), and the growth rates for the load forecasts that resulted from subtracting different amounts of DSM from the base load projection, which resulted in load forecasts that were then used for modeling purposes to evaluate alternative resource plans. The Low Modeling Forecast resulted from applying the greatest level of DSM reductions ("High DSM Case") to the base load forecast, while the High Modeling Forecast resulted from applying the lowest level of DSM reductions ("Low DSM Case") to the base forecast. The load forecasts that were developed and strictly reported in the table on page 11 provide a forecast range that the Company consider to be reasonable, while the actual forecasts used in modeling analyses are barely any different than the medium forecast.

Table 5

Load Forecast Comparison
Compound Avg Growth Rates
2020-2034

	Used in IRP Table Page 11 Only			Used in Modeling		
	Annual Sales	Peak Demand		Annual Sales	Peak Demand	
		Summer	Winter		Summer	Winter
	(%)	(%)	(%)	(%)	(%)	(%)
Low Forecast	0.25%	0.49%	0.54%	0.32%	0.53%	0.60%
Medium Forecast	0.46%	0.70%	0.75%	0.46%	0.70%	0.75%
High Forecast	1.70%	1.94%	1.99%	0.58%	0.84%	0.87%

The primary issue with the forecasts that the Company used for modeling purposes is that they do not demonstrate a wide enough range to provide sufficient information about the impacts of high and low load sensitivity cases. In addition to presenting the "economic scenarios" load forecasts in a table in the IRP Report, the Company should have also used the "economic scenarios" load forecasts in sensitivity modeling analyses that it performed to evaluate alternative resource plans.

Load and Energy Forecast Recommendations

ORS provides the following recommendations regarding the Company's load and energy forecasts:

1. The Company's IRP should provide a more thorough presentation of its load and energy forecasting methodology in future IRPs. The Company's load and energy forecast was presented in general terms only, with little specific information on how the forecast was actually performed, particularly the peak load forecast. While the Company does present more detailed information as exhibits to the Company's testimony, in future IRPs and IRP updates, the detailed support for the load and energy forecasts should be presented in the IRP Report, or in an appendix to the report.

2. The Company should improve its residential and commercial peak load forecasts to reflect the type of behavioral factors that are likely to impact peak demand over time, such as changes in appliance saturation and appliance efficiency improvements, other than caused exclusively by federally mandated requirements.

3. The Company should expand the number of sensitivities it analyzes to include both DSM scenarios and actual load growth scenarios in the expansion plan and economic analyses it performs in future IRPs. While the Company developed low, medium, and high load forecast scenarios based on "economic scenarios" in compliance with Section 40(B)(1)(a), the Company did not carry those scenarios through to conduct expansion plan and economic analyses of those forecasts.

Reserve Margin Planning

This section reviews the Company's 2020 IRP Reserve Margin Policy that establishes the summer and winter period "peak" and "base" reserve margin targets. As discussed below, the overall finding is that the primary peaking reserve margins for the summer and winter peak periods of 14% and 21%, respectively, are reasonable. However, ORS has identified concerns with DESC's reserve margin methodology and recommends that these be addressed by the Company in future IRPs and, to the extent feasible, in the next IRP update in 2021.

A utility's planning reserve margin is designed to ensure that a reasonable level of capacity reserves are targeted in order to maintain reliability and satisfy the system's peak load requirements. DESC uses a two-level summer and winter peak reserve margin requirement for planning purposes. The DESC methodology calculates both a base load reserve margin and a peaking reserve margin for both the summer and winter peaks. The Company describes its reserve policy by stating, "Peaking reserves are considered the capacity needed during the five highest peak load days in the season while base reserves are needed for the balance of the season."[36] The immediate concern with this policy is that it is not strictly a reliability-based criteria, but instead an economic criteria. Ordinarily, an expansion planning model is used to determine the type and timing of adding new capacity, and it assesses for example, whether and what type of peaking capacity would be needed to meet peak loads 5, 10, 30 or more days per year.

The following table summarizes the Company's planning reserve margin targets that were used in the IRP.

Table 6
2020 IRP Planning Reserve Margins

	Summer	Winter
Base	12%	14%
Peaking	2%	7%
Total	14%	21%

The Company uses a building block approach to develop these reserve margin targets that separately attempt to estimate the reliability risk associated with summer and winter peak demand and supply resources. In general, there are two primary sources of risk that affect a system's ability to satisfy customer load requirements. These are load variation due to weather and resource availability, which is a function of generating unit forced outage rates. DESC has attempted to measure these two (2) primary sources of risk in its reserve margin methodology.

The Company's reserve margin requirements to meet the expected summer and winter peaks are developed by considering separate components including: an estimate of demand risk during the summer and winter periods, an estimate of supply risk during the summer and winter periods, and a 200 MW capacity component associated with the Company's VACAR operating reserve requirement. Table 7 below summarizes the composition of the Company's reserve margin calculation for peaking reserves.

[36] DESC 2020 IRP Report at pg. 37.

Table 7

DESC Reserve Margin Components - Summer and Winter

	Summer	Winter
VACAR	200	200
Demand Risk	245	556
Supply Risk	234	223
Total Reserve mW	679	979
Normal Peak	4763	4852
Reserve Margin*	**14%**	**20%**

* DESC's Reserve Margin Policy sets the winter value to 21%.

The Company also computes a base reserve margin policy which is designed to reflect required reserves in non-peak months; though it was initially unclear from a review of the IRP Report, the Company's testimony, and DESC's responses to discovery, how the base reserve margin policy actually impacts long term resource planning. However, based on multiple discovery responses, it appears that while the Company did use the base reserve margin policy to determine the need for long term capacity in its economic modeling in this IRP, that approach is not necessarily the Company's actual reserve margin policy that it uses for making long term resource planning decisions.

On page 38 of the IRP Report, the Company states that the "Peaking reserve margin assists in quantifying reliability risk <u>but is not used for deciding on permanent capacity resources</u>. In response to discovery,[37] DESC states that "For the purpose of resource planning, <u>the peaking reserve margin is not used for deciding on</u> <u>long term capacity resources in the eight resource plans</u>." (emphasis added). These statements imply that the base reserve margin drives the need for long term capacity on the system. In another discovery response,[38] the Company states as follows:

> DESC conducts its resource planning studies in two steps to identify the base level of resources and then the peaking level of resources. Step 1 involves finding the most economic and reliable generating resources "to maintain a 12% summer reserve margin or a 14% winter reserve margin" whichever is most limiting in a given forecast year. Step 2 involves finding the most economic and reliable peaking resources to meet the 21% winter reserve

[37] ORS AIR 2-9b.
[38] ORS AIR 2-10.

> margin or the 14% summer reserve margin. <u>Peaking resources will most likely be provided by a demand response program or a seasonal peak capacity purchase.</u> (emphasis added).

In response to discovery, the Company further states as follows:[39]

> For the summer months which include May through October, DESC requires base reserves in the amount of 12% of the summer peak load forecast to operate the system reliably and <u>requires additional reserves in the amount of 2% of summer peak load during the peak load periods</u>. For the winter months of November through April, DESC requires base reserves in the amount of 14% of the winter peak load forecast to operate the system reliably and <u>requires additional reserves in the amount of 7% of the winter peak load forecast during the peak load periods.</u>

However, in response to discovery concerning a request for confirmation that the Company would only add generation resources to meet deficiencies in the event that total winter period production capacity falls below 114% of the expected gross territorial winter peak, or in the event that the total summer period production capacity falls below 112% of the expected gross territorial summer peak, the Company states:[40]

> The Company cannot make such a confirmation. The Company has used 114% of expected gross territorial winter peak and 112% of expected gross territorial summer peak as the trigger for addition of capacity in its planning models. However, the Company reserves the right to change those triggers and to otherwise add capacity resources to maintain reliability and maximize system economy.

Based on all of these statements, the Company's actual Reserve Margin Policy can simply be understood to be:

- DESC must maintain a minimum amount of reserves of 14% and 21% to meet the summer and winter peak load requirements, respectively, though the Company determined that the winter is always the constraining period.
- The Company assumed that it would meet the constraining winter peak reserve margin requirement by using long term capacity resources for 14%

[39] ORS AIR 2-14.
[40] ORS AIR 2-9a.

of the capacity reserve requirement, and short-term capacity purchases or additional DR for the remaining 7% of the capacity reserve requirement.

- However, in the future, the Company's actual resource plan to meet the constraining 21% winter peak reserve margin may or may not be limited to short term purchases or additional DR.

The Company needs to provide a concise Reserve Margin target definition that it utilizes for planning purposes and it should allow its economic analysis modeling process to be able to determine what type of resource to add to satisfy its reserve requirement. Based on all of the statements made by the Company, DESC must meet its peaking reserve criteria. While it may be that the least cost resource plan that will meet this reserve margin requirement consists of long term resources, additional DR, and short term capacity purchases, this does not change the reserve margin obligation, which is a requirement that the Company must have capacity sufficient to meet the summer peak plus a 14% reserve margin target and the winter peak plus a 21% reserve margin target.

There is also evidence to suggest the Company might not meet the additional 7% peaking reserve margin target using short term capacity purchases, based on the Wateree 2 unit outage event. In a discussion between ORS and the Company on June 23, 2020, the Company stated that it believes it needs to repair the Wateree 2 unit in order to maintain sufficient reliability. This suggests that the Company believes going forward it needs to have physical capacity to meet its peaking reserve margin criterion of 21% in the winter and it cannot rely on short term capacity purchases to satisfy its resource needs. This is another example of why the Company should clarify its reserve margin policy.

As mentioned above, the Company uses a building block approach to develop its 21% and 14% winter and summer peaking reserve margin targets by accounting for three (3) components. The first is load variation due to weather, and in order to estimate the potential risks weather poses, the Company estimates its summer and winter "demand risk" using a regression approach that incorporates historical seasonal peak loads and weather for the past three (3) years.[41]

From this analysis, the Company evaluated the variability in weather during worst case conditions over the past twenty-eight (28) years (1991 to 2018) and the Company

[41] The Company estimates this model using a number of different specifications (e.g., quadratic, linear) and based on alternative data bases (e.g., all summer or winter days in which cooling degree hours ("CDH") and heating degree hours ("HDH") were greater than "0", during the top 100 weather days).

determined that the variability in summer peak demand based on normal peak weather and extreme, worst case peak weather is 245 MW. For the winter peak, the variability is much greater (557 MW), due to the much larger variation in extreme winter weather conditions.[42]

While conceptually the Company's demand risk analysis does measure the risk of extreme weather on peak loads, the DESC approach of basing this measurement on the worst case weather, rather than a probabilistic measure of the entire weather distribution during the past 28 years, sets the peaking reserve margin at a level designed to meet a 1-in-28 year weather condition. The Company performs no analysis in its IRP to determine the economic tradeoffs of the costs needed to meet this criterion versus the costs to customers of a failure to meet this 1-in-28 year peak load weather condition. Other utilities in the region perform reliability evaluations using an economic based approach to determine an optimal reserve margin. In this type of analysis, the supply costs of meeting various reserve margin levels are compared to the value of lost load to determine an economically optimal level of reserves. This is the approach used by Georgia Power Company, Tennessee Valley Authority ("TVA"), and Louisville Gas and Electric Company and Kentucky Utilities Company. Duke Energy also performs this type of analysis, but relies on an LOLE reliability approach as its primary reserve margin determinant.

Next, the Company performed a supply risk analysis associated with generator outages and derations. For this analysis, the Company developed a probability table showing the percentage of time during the summer and winter periods that various levels of generating capacity have been lost in the past due to outages and derations. The Company then set the "supply risk" at the MW level associated with a 70% probability of occurrence, which the Company determined was equivalent to 234 MW of reserves in the summer and 223 MWs in the winter. In other words, based on its historic analysis over the period from 2010 to 2017, the Company expects that in the future it will likely lose 234 MW of capacity in the summer and 223 MWs in the winter due to outages and derations during 70% of the days in the respective summer and winter periods. The Company supported its selection of a 70% probability level based on the following:[43]

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[42] For the summer demand risk analysis, the most extreme weather over the twenty-eight (28) year period occurred on August 14, 1995, while for the winter analysis, the most extreme weather occurred on January 24, 2003.
[43] ORS AIR 2-16a.

At 70% the supply resource probability outage curve began to increase significantly which made it a good cutoff point.

Based on this response, there is no underlying basis for the selection of the 70% risk level. Since this probability contributes to the determination of the Company's summer and winter peak reserve margin targets, which in turn, drives the resource planning economic analyses, it would be appropriate for the Company to provide an economic based justification for the Company's assumptions. Table 8 below shows the alternative levels the Company could have selected.

Table 8

Reserve Margin vs. MW Forced Out by Percentile

Percentile	50%	60%	70%	80%	90%	100%
Summer	106	152	234	385	618	1,402
Implied Reserve Margin	12%	13%	14%	17%	22%	39%
Winter	121	165	223	373	520	1,552
Implied Reserve Margin	18%	19%	20%	23%	26%	48%

This table, which is based on Table 3 in Dr. Lynch's Exhibit JML-3, also includes the corresponding summer and winter reserve margins that would be implied based on the different probability levels. It is clear that the selection of the supply risk level significantly impacts the required level of capacity reserves in DESC's analysis and the Company should be required to provide economic support for its selection of a 70% reserve margin in future IRPs.

The third component of the Company's reserve margin calculation is the addition of 200 MW of assumed reserve capacity associated with the VACAR operating reserve requirement. The use of an operating reserve component appears to be a fairly unique aspect of DESC's reserve margin calculation compared to other utilities. The Company's VACAR assumption simply results in the Company including an additional 200 MW of capacity planning reserves on its system that is attributed to an operating reserve requirement.

There is a difference between an operating reserve requirement and a planning reserve obligation. An operating reserve requirement is normally used in the day-to-day utility commitment and dispatch process and is designed to ensure that enough capacity is online and available to meet load requirements in the event of a sudden forced outage, unit deration, or large ramp-up of load. Because the Company is part of the VACAR Reserve Sharing Agreement, the VACAR rules help establish the Company's operating reserve requirement. Other utilities also have operating reserve requirements, but they do not simply add their operating reserve requirement in as an additional component to their planning reserve requirement. Typically, a planning reserve margin calculation derives the appropriate amount of planning reserves a utility needs to ensure reliability, and once that is determined it is understood that there will be sufficient operating reserves needed for the real-time operation of the system.

ORS considered one more aspect of the Company's reserve margin policy, which relates to the use of an LOLE study. In response to a discovery request,[44] the Company supplied an LOLE study that determined the summer and winter peak reserve margin target needed to achieve a 1-day-in-10 year LOLE, which has been the industry standard for decades. However, the Company neither relied on that LOLE analysis to establish its Reserve Margin policy for this IRP, nor mentioned it in either the IRP Report or any of its direct testimony filed in this docket. In discovery, the Company referenced another docket related to a fuel proceeding in which Dr. Lynch did address the use of an LOLE analysis to determine a planning reserve margin target. Beginning on page 21 of that testimony, Dr. Lynch testified as follows:[45]

> **Q. DID DESC RELY ON A LOSS OF LOAD EXPECTATION ("LOLE") STUDY TO ESTABLISH ITS RESERVE MARGIN POLICY? IF NOT, WHY PRESENT IT IN THIS DOCKET?**
>
> A. DESC has made LOLE calculations for many years and reported the results in its IRPs over those years. However, DESC does not rely on LOLE calculations to establish its reserve margin policy but has reported them as support of its policy. A formal LOLE study is being presented in this docket and is attached as Exhibit No. __ (JML-4) because LOLE is prevalent in the industry for establishing a reserve margin and a desire for these LOLE calculations was expressed in last year's fuel docket.

The DESC LOLE study was provided in response to discovery[46] and indicated that a minimum reserve margin requirement ranging from 17% to 18%, applied to the annual winter system peak, would achieve an LOLE of 1-day-in-10 years. Interestingly, this is close to the same range of the current planning reserve margin criterion used by Duke Energy in South Carolina.

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[44] ORS AIR 1-21b.
[45] Docket No. 2019-184-E.
[46] ORS AIR 1-21b.

On page 10 of the LOLE study, and in Dr. Lynch's 2019 testimony, he presents a hypothetical that he asserts supports the Company's rejection of the use of an LOLE methodology to develop a planning reserve margin target. There are a couple of problems with Dr. Lynch's position, but first, it should be noted that the argument he uses would be applicable to almost any electric utility that experiences system peaks at the time of an extreme weather condition.

Dr. Lynch's primary concern with an LOLE planning criterion is that it is not focused exclusively on meeting system peaks, but rather on achieving a specified level of reliability based on limiting customer outages to no more than one (1) event (day) in ten (10) years resulting from an insufficient amount of generation resources. Contrary to Dr. Lynch's position, as mentioned above, this generally is, and has been the industry standard for decades and is the reliability standard used by the PJM Interconnection LLC ("PJM") Regional Transmission Organization ("RTO") and many individual utilities.

The second problem with the Company's argument against the use of an LOLE criterion is that it assumes that the purpose of maintaining generating reserves is to ensure that there is sufficient capacity available to meet almost any extreme weather event. Under the Company's preferred method, capacity is acquired to meet the most extreme winter weather that occurred in the past twenty-eight (28) years. While this may be a reasonable criterion, and, in practice, results in a winter reserve margin that is not appreciably greater than the Company's LOLE results (21% vs. 17% - 18%), the Company's reserve margin criteria does not evaluate the level of reliability that is associated with its policy. In other words, the Company appears to be exceeding a 1-day-in-10 year criterion, but it is not clear whether the reliability level that it is actually planning for is 1-day-in-15 years, 1-day-in-20 years, or some other criterion that is even higher.

Notwithstanding this, the DESC Reserve Margin Policy produces a winter reserve margin that exceeds the corresponding LOLE determined reserve margin. It is clear that the reliability level achieved using the DESC method will at a minimum be greater than a 1-day-in-10 year outage expectation. It is not unusual for utilities to use an LOLE criterion greater than 1-day-in-10 years, such as Florida Power & Light Company and Georgia Power Company as two examples, however, the Company should determine what LOLE level it is planning for.

The overall assessment of the Company's Reserve Margin Policy is that the resulting summer and winter peak reserve margins are not unreasonable, based on recent reserve margin targets used by other utilities in the region. For example, Georgia Power Company uses a summer reserve margin of 16.25% and a winter peak reserve margin target of 26%;[47] Florida Power & Light Company uses a 20% reserve margin criterion and Louisville Gas and Electric Company and Kentucky Utilities Company use a target reserve margin that ranges between 17% and 25%.[48] While concerns have been identified with some aspects of the Company's methodology itself, the end result is that DESC's planning reserve margin requirements do not appear to be out of line with other regional utilities. Moreover, because the Company does not need to add new resources until 2034, or possibly 2028, DESC will have an opportunity to address the concerns identified by ORS in a future IRP update or filing.

In conclusion, ORS recommends that the Company provide more justification in future IRPs and IRP updates to support the use of its methodology.

Reserve Margin Planning Recommendations

ORS provides the following recommendations regarding the Company's reserve margin policy:

1. The Company should include a detailed analysis of its reserve margin methodology in future IRPs, which could be included as an appendix to the IRP Report. At a minimum, the Company should provide:

   1.1. Additional explanation of the Company's dual reserve margin criteria (base reserves, peaking reserves). There is an insufficient explanation of the applicability of either criterion in the IRP Report and in the testimony of DESC witnesses.

   1.2. A stronger foundation for inclusion of the VACAR operating reserve obligation as a component in the calculation of its long term resource planning reserve margin. The VACAR operating reserve obligation is a short term operating reserve obligation, not a long-term planning criteria and does not appear to be consistent with general industry practice.

2. With regard to reserve margin modeling methodologies in future IRPs:

   2.1. The Company should consider utilizing an optimal economic based reserve margin methodology that considers the cost to customers of unserved load and energy compared to the cost of meeting various levels of reliability.

[47] The Georgia Public Service Commission, in its order in Docket No. 42310 approved a stipulation that did not include any specific approval of the Company's requested 26% winter reserve margin.
[48] This is based on the Companies' 2018 Reserve Margin Study.

2.2. The Company should incorporate a traditional LOLE analysis and should present the results of a more comprehensive LOLE analysis that includes probability assessments of the impact on peak loads of varying weather conditions, and also considers the impacts of a reasonable amount of tie line support from neighboring utilities.

Demand Side Management

The Company's IRP included both energy efficiency and DR DSM programs in its IRP analyses. The programs that the Company included were recently reviewed in Docket No. 2019-239-E, in which a comprehensive DSM evaluation was conducted. On December 20, 2019, the Commission issued Order No. 2019-880 approving the Company's proposed suite of ten DSM programs along with a five-year program implementation plan. In that order, the Commission found that DESC's suite of DSM programs, "represents an appropriate and reasonable approach for implementing DSM measures that are in the public interest."[49] The Company's suite of ten (10) DSM programs were developed in a study the Company conducted entitled, *Dominion Energy South Carolina: 2020–2029 Achievable DSM Potential and PY10–PY14 Program Plan* (the "2019 Potential Study").

The ten programs, including seven for residential customers and three for commercial and industrial customers are:

<u>Residential Programs</u>

- Home Energy Reports
- Home Energy Check-up
- Energy Wise Savings Store
- Heating and Cooling Program
- Neighborhood Energy Efficiency Program
- Appliance Recycling Program
- Multifamily program

<u>Commercial and Industrial Programs</u>

- EnergyWise for Your Business Program
- Small Business Energy Solutions Program

[49] Docket No. 2019-239-E, Order No. 2019-880, December 20, 2019, at pg. 27.

- Municipal LED Lighting Program

Descriptions of each of these programs may be found at page 18 of the Company's IRP Report. The Company used the approved programs as the basis for developing the Medium DSM case used in the IRP. The Medium DSM case used the same amount of annual energy savings as determined in the 2019 Potential Study, and according to DESC witness Therese Griffin, the programs included in the 2019 Potential Study effectively doubled DESC's planned DSM program spending and increased annual energy efficiency savings from the previous planned amount of .33% to .7%.[50] In addition, the Company assumed that by 2029, it would achieve an additional 43 MW of DR winter peak savings reductions based on the installation of AMI meters, assuming the Company is able to appropriately roll out the AMI meters.[51]

In addition to the Medium DSM case, the Company also created low and high DSM sensitivity cases. The low case DSM case represents the continuation of existing energy efficiency programs prior to 2019 Potential Study, which as mentioned represents an annual energy savings level of .33%. No additional DR was included in that case. The high DSM case assumes that DSM programs result in an annual energy savings of 1% of retail sales by 2022 and includes 150 MW of additional DR winter peak savings reductions.[52]

The Company also created one additional DSM case to conduct the SCSBA RP analyses, which started from the Company's 2019 DSM potential study forecast and scaled up the energy savings each year by 0.25% from the previous year's savings until it reached 1.25% in annual energy savings.

There are two issues ORS identified with regards to the Company's treatment of the DSM forecasts in its IRP analyses. The first issue has already been discussed in the load section of this report and is the fact that the Company only conducted load forecast sensitivity studies using DSM adjustments, and did not conduct any analyses of reasonable load sensitivity cases. As Table 5 above indicates, there is a considerable difference in load impacts based on DSM sensitivities compared to load forecast sensitivities. Furthermore, while DSM does directly affect peak and energy requirements, these effects are realized through conservations programs developed by the Company and involve the customers' participation, while load forecast sensitivities generally capture

[50] Direct Testimony of Therese Griffin, at pg. 26, ln. 18. Ms. Griffin stated her figures were calculated net of the 438 commercial and industrial opt-out customers.
[51] IRP Report at pg. 23.
[52] ORS AIR 1-1b.

impacts such as population growth in the service area, and overall economic activity (income, industrial production). ORS's recommendation regarding this matter is presented in the Load and Energy Forecast Section above.

The second issue concerns the Company's characterization of its high DSM sensitivity case. While the Company was the party responsible for developing the case, it asserted that the case is "not likely to be achievable"[53], and that "this case in the IRP in no way indicates that DESC believes that it is reasonable or achievable".[54]

Since the Company was solely responsible for the development of its cases in the IRP, it is unclear why it would not have been able to develop a reasonable high DSM forecast that it could have used for sensitivity analysis that it believes is reasonable and achievable.

Aside from these issues, ORS is generally satisfied with the DSM scenarios that the Company relied on for purposes of this IRP, particularly since the Commission recently approved the DSM programs that the Company used as the basis for the DSM forecasts included in this IRP. ORS provides the following recommendation regarding the Company's DSM forecasts.

Demand Side Management Recommendation

The Company should only use DSM assumptions for its RPs and sensitivities that it has confidence in and believes are reasonable and achievable in future IRPs.

Natural Gas Price Forecasts

The Company developed three natural gas price forecasts, including a low, base, and high forecast. The Company set its low and base gas price forecasts between January 2020 and December 2022 equal to the monthly NYMEX Henry Hub natural gas futures prices that were pulled from NYMEX on 12/20/2019. For its low gas price forecast, it escalated these prices at approximately 2.2%, and then dropped the escalation rate to approximately 1.5% in 2033 for the remainder of the modeling period. The Company developed its low gas price escalation rates by simply using an escalation rate equal to half the escalation rate the Energy Information Administration EIA used in its 2019 Annual Energy Outlook ("AEO") "Reference" gas price forecast.[55] The Company derived its

[53] Attachment provided in response to ORS AIR 1-7.
[54] Direct Testimony of Eric Bell, at pg. 11, ln. 10.
[55] The Company's response to ORS AIR 1-18 indicated that it relied on EIA's Low Oil and Natural Gas Resource and Technology Case to derive it low case escalation rates.

escalation rates based on EIA's AEO Table 3, which contain delivered natural gas prices to electric utilities.

The Company derived its base gas price forecast using the same monthly NYMEX futures prices between January 2020 and December 2022. For escalation rates it used exactly the same escalation rates as used in the EIA 2019 Reference gas price forecast, which were 4.4% for the period of 2023 through 2032, and 3% from 2033 until the end of the modeling period. For its high gas price forecast, the Company directly used EIA's AEO 2019 "Reference" Henry Hub forecast, as found in Table 1 of the 2019 AEO report. Table 1 is strictly the Henry Hub commodity price forecast and does not include delivery charges.

Other than comparing to EIA forecasts, the Company did not compare its forecasts to any other forecasts as a reasonableness check, which ORS has done.[56] The following three graphs compare the Company's low, base and high gas price forecasts to other recent utility and industry forecasts that are publicly available. Furthermore, ORS computed a "consensus forecast" (low, base, high) by averaging together the publicly available forecasts each year, including DESC's gas price forecasts. The other utility forecasts were from recent IRPs, including Entergy Louisiana LLC,[57] Xcel Energy,[58] PacifiCorp,[59] Virginia Electric and Power Company,[60] and Kentucky Power Company.[61] In addition, EIA[62] forecasts also were used, including EIA's High Oil and Gas Supply forecast in the low consensus forecast, EIA's Reference Case in the base consensus forecast, and EIA's Low Oil and Gas Supply in the high consensus forecast.

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[56] ORS AIR 1-18.
[57] "Data Assumptions and Study Description", pg. 22. https://www.entergy-louisiana.com/userfiles/content/irp/2019/ELL_2019_IRP_Assumptions.pdf
[58] Response to Xcel Large Industrials Information Request No. 18, https://www.edockets.state.mn.us/EFiling/edockets/searchDocuments.do?method=showPoup&documentId={306CC06C-0000-C433-8D9B-4E20400293F9}&documentTitle=20198-155420-02
[59] Filed October 25 2019 under Docket 19-035-02, HighGas - High CO2.xlsx, LowGas - Low CO2.xlsx, MedGas - 2025MCO2.xlsx, https://psc.utah.gov/2019/01/28/docket-no-19-035-02/
[60] Virginia Electric and Power Company's 2020 Integrated Resource Plan, Appendix 4O, pg 4. https://www.dominionenergy.com/library/domcom/media/about-us/making-energy/2020-va-integrated-resource-plan.pdf?modified=20200501191108
[61] Kentucky Power Integrated Resource Planning Report, p. 78. https://psc.ky.gov/pscecf/2019-00443/sebishop%40aep.com/12202019120748/KPCO_2019_IRP_Volume_A_Public_Version.pdf
[62] Annual Energy Outlook 2020; Table 13. Natural Gas Supply, Disposition, and Prices. https://www.eia.gov/outlooks/aeo/data/browser/#/?id=13-AEO2020&region=0-0&cases=ref2020~highogs~lowogs&start=2018&end=2050&f=A&linechart=~~~~~~~~~ref2020-d112119a.60-13-AEO2020~highogs-d112619a.60-13-AEO2020~lowogs-d112619a.60-13-AEO2020&map=&ctype=linechart&sourcekey=0

Figure 5

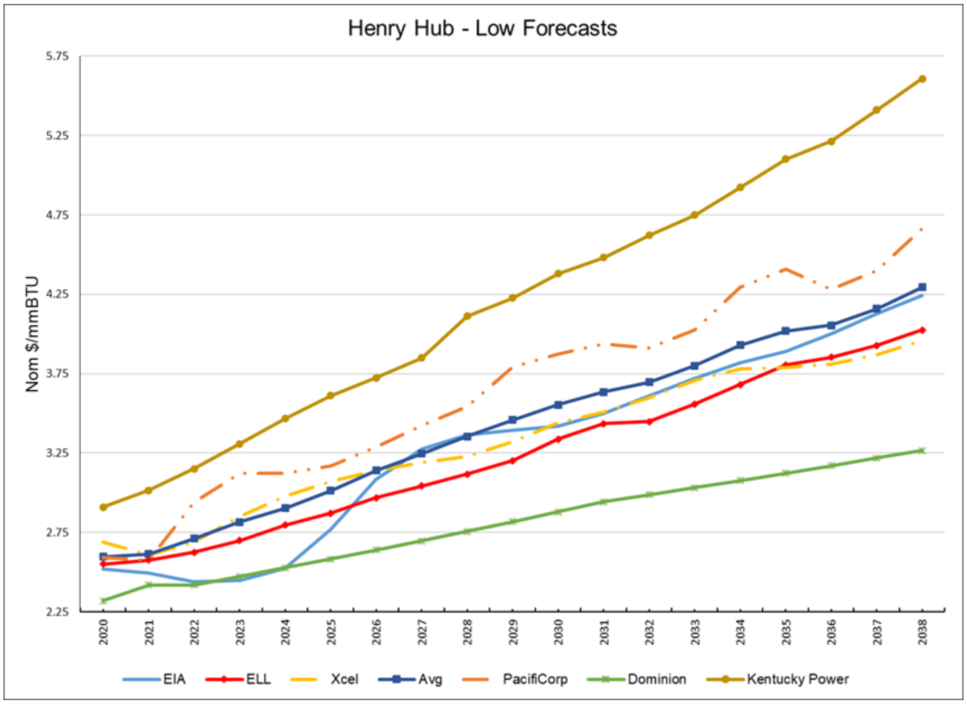


Figure 6

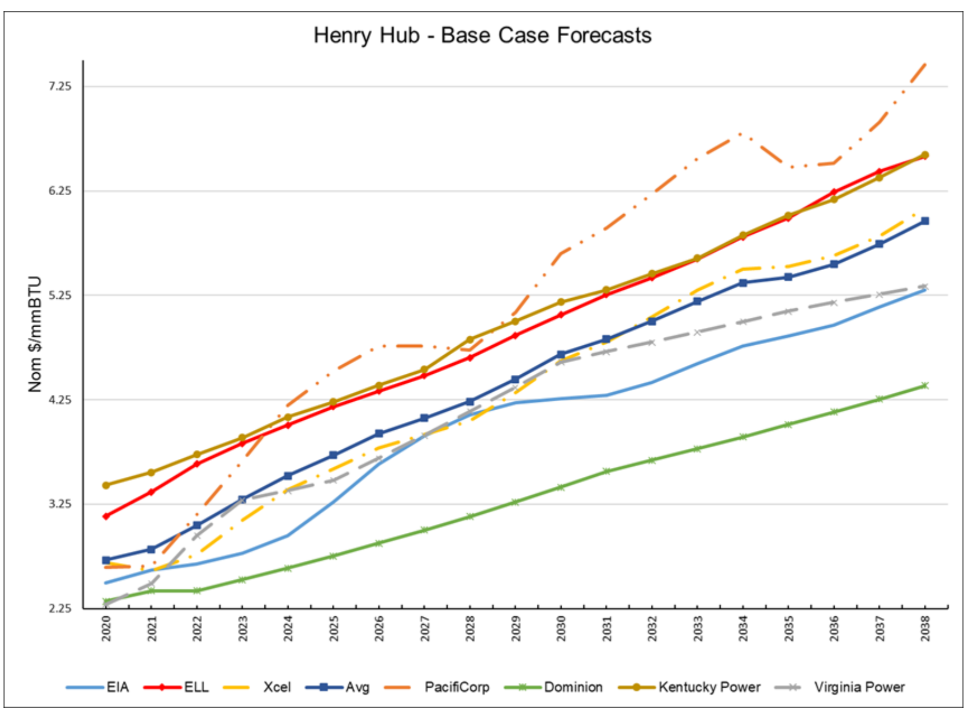
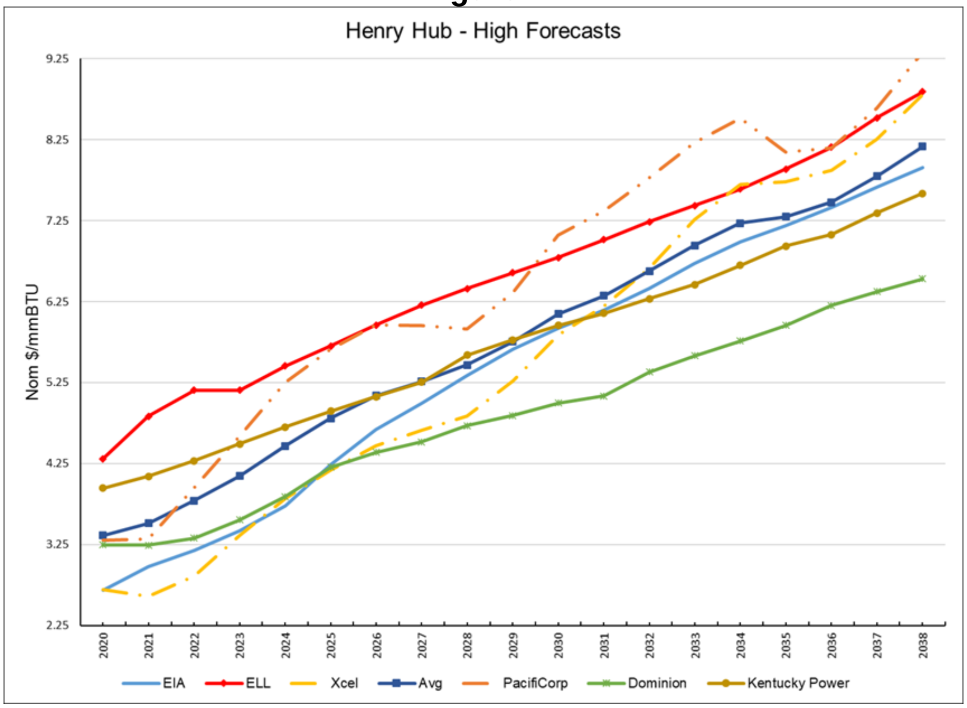


Figure 7



The DESC gas price forecasts are lower than the comparative forecasts, including the consensus forecast in all three (3) gas price cases. ORS recognizes that the future is unknown and that natural gas price forecasts have dropped considerably over the last ten years.

The Company's use of the NYMEX futures for the next three years (3) as the starting point for the Company's low and base gas price forecasts is reasonable. However, the Company's use of the AEO 2019 Reference forecast as the basis for the high gas price forecast appears to be arbitrary simply to have a source for a high gas price forecast.

In addition, ORS is concerned that the Company's escalation methodology may understate gas prices beyond the initial three year forecast in the low and base gas price sensitivities. The escalation factors in the gas price sensitivities are developed from the AEO 2019 Reference case forecast, which itself did not use the same NYMEX futures as the starting point. The low gas price forecast uses escalation rates equal to one-half the escalation rates in the AEO 2019 Reference case. The base gas price forecast uses the same escalation rates as the AEO 2019 Reference case. The use of the escalation factors reflected in the AEO 2019 Reference case also appears to be arbitrary and is methodologically inconsistent with the use of the NYMEX futures from a later date as the starting point in the low and base gas price forecasts.

Finally, the Company's IRP does not discuss the availability and constraints of the Company's natural gas pipeline capacity and supply, including timelines for the potential new sources of capacity and supply necessary to supply fuel to new CC and ICT resource additions. The lack of available pipeline capacity was a factor in the Company's selection of resources in the RPs considered in the IRP.

Natural Gas Price Forecast Recommendations

1. The Company should review its gas price forecasting methodology and investigate alternative approaches for use in future IRPs. Although the use of NYMEX futures is a reasonable starting point for developing gas price forecasts, the Company should consider potential alternative escalation methodologies. In future IRPs, the Company should also compare its gas price forecasts to those developed and/or relied on by other utilities in their IRPs to assess the range and reasonableness of its forecasts.

2. The Company should address the availability and constraints of natural gas pipeline capacity and supply on the timing, size, and location of potential new CC and ICT resource additions in future IRP filings.

CO_2 Price Forecasts

In the Conclusion section of the IRP Report, the Company acknowledged it is taking steps to "produce a more sustainable future", but it also notes that "those steps must be affordable." It is reasonable that despite the fact that no federal or state requirements have been implemented at this time mandating consideration of carbon costs, the Company modeled CO_2 tax price sensitivity cases, including $0/ton and $25/ton cases. Those assumptions were agreed upon in the November 30, 2018, Merger Settlement Agreement between SCE&G, Dominion Energy, and the SCSBA. For the $25/ton CO_2 case, the Company assumed the tax would begin in January 2025, and would escalate at 2% per year thereafter. Table 9 compares the CO_2 tax forecasts developed by DESC to those developed by Xcel Energy,[63] PacifiCorp,[64] Kentucky Power Company,[65] and Virginia Electric and Power Company.[66]

Table 9

CO2 Tax Forecast Comparison

Utility Forecast	DESC	Xcel Low	Xcel Mid	Xcel High	PacifiCorp Med	PacifiCorp High	PacifiCorp Societal	KP	VP Low	VP Med	VP High
Escalation (%)	2.00%	2.00%	2.00%	2.00%	12.49%	10.62%	4.06%	3.50%	3.29%	6.00%	6.64%
2025 Price ($/Ton)	$25	$5	$15	$25	$10	$23	$59	$15	$6	$6	$0
2049 Price ($/Ton)	$40.21	$8.04	$24.13	$40.21	$167.13	$254.27	$153.73	$30.89	$12.61	$25.92	$116.27

DESC's CO_2 price forecast uses a low escalation rate of 2%, but starts at a relatively high price of $25/ton, though Xcel also includes an identical case in its modeling analyses. The lowest of all CO_2 price forecasts are Xcel's "Low" and Virginia Electric and Power Company's "Low" scenarios, which both begin at $5/ton and $6/ton respectively in 2025 and escalate at 2% and 3.3%. The highest CO_2 price forecast is PacifiCorp's "High" case, which begins at $23/ton in 2025 and escalates at 10.62% a year, reaching $254/ton by 2049.

Given the uncertainty surrounding future environmental regulations, and this comparison to other industry forecasts, ORS does not find DESC's CO_2 forecast to be unreasonable. The current ACE Rule in place is currently under appeal, and may be modified or removed in the future. In addition, this ACE Rule was finalized in June 2019, and included the final repeal of the prior administration's Clean Power Plan ("CPP").[67] This highlights the uncertainty and administration-dependent nature of EPA regulations, which are particularly evident in an election year.

[63] Appendix F2: Strategist Modeling Assumptions & Inputs, pg. 3; Xcel Energy 2020-2034 Upper Midwest Resource Plan.
[64] Chapter 7 – Figure 7.3 CO2 Prices, https://pscdocs.utah.gov/electric/19docs/1903502/310626Chapter7Figure7.3CO2Prices10-25-2019.xlsx
[65] Significant Changes from 2016 IRP, pg. 5, Kentucky Power 2019 Integrated Resource Planning Report; https://psc.ky.gov/pscecf/2019-00443/sebishop%40aep.com/12202019120748/KPCO_2019_IRP_Volume_A_Public_Version.pdf
[66] ICF Commodity Forecast: CO2, Appendix 4O, Virginia Electric and Power Company's 2020 Integrated Resource Plan; https://www.dominionenergy.com/library/domcom/media/about-us/making-energy/2020-va-integrated-resource-plan.pdf?modified=20200501191108
[67] https://www.epa.gov/stationary-sources-air-pollution/affordable-clean-energy-rule

While ORS finds that the Company's forecast is not unreasonable, it concludes that the Company should examine a wider range of CO_2 forecasts in future IRPs. Most of the utilities that were examined included at least two forecasts besides a \$0/ton CO_2 case in their modeling analyses. This includes Georgia Power Company, which uses \$0/ton, \$10/ton, and \$20/ton CO_2 price forecasts.[68] In addition, while DESC's use of the general inflation rate of 2% makes sense from an economic perspective, the implementation of a tax on carbon emissions with the goal of decarbonization to specific levels in the future may require CO_2 prices to escalate at a higher rate, such as escalation rates that PacifiCorp and Virginia Electric and Power Company have studied. Just as DESC considered three natural gas price forecasts, it would be better for the Company to provide a wider range of CO_2 prices for sensitivity evaluation in its analyses.

CO_2 Price Forecast Recommendation

The Company should examine additional CO_2 price sensitivities by including a third CO_2 forecast, consistent with industry practice, in future IRPs.

Existing System Resources

DESC has a diverse fleet of generating resources that consist of coal-fired steam, gas-fired steam, nuclear, gas turbines, hydro, and solar units. The following table[69] provides a list of the Company's resources, and includes the probable retirement dates and the nameplate capacity of each resource based on the winter capacity rating, since the Company asserts that the winter period is more constraining from a need for capacity perspective.

[68] Bell's Direct Testimony, Exhibit 2, page 73.

[69] This information was summarized from page 33 of the Company's IRP report. Note that the probable retirement dates were based on the Company's 2014 Depreciation Study, and the solar values do not account for the Company's assumption regarding solar capacity value.

Table 10

DESC Existing Supply Side Resources	Probable Retirement Date (Year)	Winter 2020 Nameplate Capacity (MW)	Total Capacity by Type (MW)
Coal-Fired Steam:			1709
Wateree	2044	684	
Williams	2047	610	
Cope[1]	2071	415	
Gas-Fired Steam:			346
McMeekin	2028	250	
Urquhart	2028	96	
Nuclear:			662
V. C. Summer	2062	662	
Gas Turbines:			2393
Urquhart 1,2,3	2044	48	
Urquhart 4	2059	49	
Coit	2029	36	
Parr	2030	73	
Williams	2057	52	
Hagood 4	2051	99	
Hagood 5	2070	21	
Hagood 6	2070	21	
Urquhart Combined Cycle	2077	484	
Jasper Combined Cycle	2079	924	
CEC Combined Cycle	2079	586	
Hydro:			800
Neal Shoals	2055	4	
Parr Shoals	2064	12	
Stevens Creek	2079	10	
Saluda	2082	198	
Fairfield Pumped Storage	2128	576	
Solar:			975
Company Owned	2031	2.4	
PPA DER	2039	64	
PPA Non-DER	2040	909	
Other:			20
Southeastern Power Administration (SEPA)		20	
Total:			6905

1. Cope Station is dual fuel and is run on both coal and natural gas.

The Company has several licensing activities underway regarding its hydro resources. The status of those activities is as follows.[70]

[70] IRP Report at pg. 23 and 24.

- Saluda River Hydro Project – An application was submitted to relicense the plant in 2008, and the Company is still awaiting the Federal Energy Regulatory Commission's ("FERC") approval of a 50-year license extension.
- Parr Hydroelectric Project – This project consists of the Parr Shoals Development and Fairfield Pumped Storage Development generating units. The license for this project is set to expire in June 2020, and the Company filed an application with FERC in June 2019 to renew the project.
- Stevens Creek Hydroelectric Project - The Company started the process of relicensing the Stevens Creek project in 2018. Its license is set to expire in 2025.

In addition, the Company plans to seek an extension of the V.C. Summer nuclear unit license. Licensing details for that unit are as follow.[71]

- V.C. Summer Nuclear Unit - The unit began operating in 1984 under a twenty (20) year license that was subsequently extended for another forty (40) years until 2042. The Company anticipates that in the future it will request a further extension of the unit's license to operate until 2062.

Out of the 6,905 MW of capacity, the Company's table indicates that 455 MW of capacity will likely retire in the next ten (10) years, and 2,772 MW of capacity will retire before the end of the IRP modeling period of 2049. The probable retirement dates shown in the table were developed in the Company's 2014 Depreciation Study.

ORS has several concerns regarding the Company's IRP with regard to existing units. First, the Company's depreciation study is approximately six (6) years old, and possibly out of date. The Company has not reassessed the retirement dates in any recent comprehensive engineering or economic analyses.

Second, the Company recognizes that it is important to reflect consideration of facility retirement assumptions in its IRP. Mr. Bell notes that the Company confected three RP scenarios "specifically premised on the early retirement of one or more existing generating units, specifically Wateree Station, McMeekin Station, Urquhart Unit 3 or Williams station."[72] In the one RP wherein the Company studied retirement at the Urquhart Unit 3 and McMeekin units, those units were set up to retire in 2028, which are the probable retirement dates shown in the preceding table from the IRP Report. In the

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[71] *Id.*
[72] Direct testimony of Eric Bell, at pg. 20, ln. 4.

other seven (7) RPs, the Company simply assumed that the two (2) units would continue to operate indefinitely beyond the probable retirement date, although none of those studies were characterized as life extension studies. It is not clear whether the Company can, or will, actually operate those units beyond 2028, given those gas-fired steam turbine units will be between seventy (70) and seventy-five (75) years old in 2028. Also, the Company assumed no incremental capital expenditures to refurbish or rebuild those units to continue to operate beyond 2028 in the seven RPs.

It is clear from this that the Company should conduct additional detailed retirement studies, and in fact, this issue is even more pressing considering the recent major outage that occurred at Wateree 2. In fact, the Company did perform a limited study that considered whether to repair or retire Wateree 2. In that study, the Company also considered whether to retire Wateree 1 early.

The Wateree 2 outage event occurred shortly before the Company filed its IRP in February of this year. DESC describes the Wateree outage event as follows:[73]

> On February 19, 2020 the Wateree 2 unit, a coal-fired unit built in 1970, was in Reserve Shutdown due to mild winter conditions and the generator had been in a dry air layup due to the duration of the outage. An isolation valve failed and hydrogen gas leaked into the generator caught fire and damaged the generator. The generator repair and replacement alternatives were estimated to cost from $20 million to $30 million and would require 12 to 24 months.

The Company's Wateree 2 studies were very limited and the Company carefully noted that they were not comprehensive "retirement" studies to determine the economic retirement date of Wateree 2 or any other resource. The Wateree 2 studies were conducted in a manner similar to the way the eight (8) RPs were evaluated in the Company's IRP analyses. As such, the Wateree 2 studies suffered from the same problems that ORS identified with the RPs in the DESC IRP, which are described in greater detail in subsequent sections of this report. In general, the issues that were identified include:

1. Several modeling errors were identified associated with the Company's PROSYM runs and its capital revenue requirement calculations that affected all of the Company's modeling analyses, including the Wateree 2 analyses. With regard to the retirement analyses, the Company did not include all costs and savings that

[73] ORS AIR 1-15

would be realized if it retired its coal-fired and certain gas-fired resources prior to or in fact at their probable retirement dates.

2. The Company did not consider the probable retirement dates of Urquhart and McMeekin in its analyses, which could influence the retirement decision of the Wateree units and the capacity resource additions necessary for its RPs.

3. The Company assumed that if it repaired the Wateree 2 unit, it would receive an insurance payout of approximately $10 million, however, it did not make a corresponding assumption about how much of an insurance payout it would receive if it retired the Wateree 2 unit.

Existing System Resources Recommendations

1. The Company should conduct a detailed retirement study and should ensure that it corrects the modeling errors identified in this report. These studies should identify proper input assumptions to capture all costs and savings that would be incurred in the retirement analysis. The studies should address all potential early retirement candidates including the Wateree, Williams, Urquhart, and McMeekin coal-fired and gas-fired steam turbine resources, as well as its older gas-fired ICT resources.

2. The Company should conduct additional modeling analyses of the Wateree 2 alternatives, in which it corrects the numerous PROSYM and capital revenue requirement errors that ORS identified and that are discussed further below. Furthermore, the Company should include insurance payout assumptions in both the Wateree 2 retirement cases and Wateree 2 continuation cases, or it should remove the insurance payout assumption from both analyses. Finally, the Company should conduct analyses with the Urquhart and McMeekin gas fired steam turbine units retired on their probable retirement dates.

3. The Company should include a discussion of the Wateree 2 outage and the evaluation that it conducted to decide when to retire or to repair the unit and should provide justification for any decision to continue to operate the unit.

Generic Resource Options

The Company identified six generic supply side units as potential expansion plan options in its resource plan analyses, which it describes in a table on page 39 of the IRP document, including BESS, Utility Solar, Solar PPA, ICT Frame J ICT, ICT Aeroderivative ICT, and CC 1x1 options. The table below includes the information the Company supplied, and compares that data to similar information obtained from other publicly available sources including Virginia Electric and Power Company,[74] Kentucky Power Company,[75] and Southwestern Electric Power Company,[76] as well as the EIA's 2020 AEO,[77] and Lazard's 2019 Levelized Cost of Energy Analysis.[78] The table includes information for capacity, capital cost and the associated escalation rate, fixed and variable operation and maintenance expenses, levelized cost of energy, average heat rate, and the expected forced outage rate for all six potential resource options.

[74] Appendix 5N – Busbar Assumptions; Appendix 5M – Tabular Results of Busbar; Virginia Electric and Power Company's 2020 Integrated Resource Plan. https://www.dominionenergy.com/library/domcom/media/about-us/making-energy/2020-va-integrated-resource-plan.pdf?modified=20200501191108

[75] Table 13. New Generation Technology Options with Key Assumptions, pg. 93, Kentucky Power 2019 Integrated Resource Planning Report; https://psc.ky.gov/pscecf/2019-00443/sebishop%40aep.com/12202019120748/KPCO_2019_IRP_Volume_A_Public_Version.pdf

[76] New Generation Technologies, pg. 32; Description of Studies & Study Assumptions. http://lpscstar.louisiana.gov/Star/portal/lpsc/page/docket-docs/PSC/DocketDetails.aspx

[77] Cost and Performance Characteristics of New Generating Technologies; U.S. Energy Information Administration's Annual Energy Outlook 2020. https://www.eia.gov/outlooks/aeo/assumptions/pdf/table_8.2.pdf

[78] Lazard's Levelized Cost of Energy Analysis – Version 13.0. https://www.lazard.com/media/451086/lazards-levelized-cost-of-energy-version-130-vf.pdf

Table 11

Generic Resource Comparison (Nominal $)

Resource Type	Battery Storage[1]					Utility Solar[3]					Solar PPA
Forcast Source	DESC	VP 2020 IRP	KP 2019 IRP	SWEPCO 2019 IRP	EIA AEO 2020	DESC	VP 2020 IRP[4]	KP 2019 IRP	EIA AEO 2020[2]	Lazard's 2019	DESC
Capacity (MW)	100	30	10	10	50	100, 400			150	100	400
Capital Cost ($/kW)	$1,911	$2,224	$1,900	$1,980	$1,414	$1,151	$1,363	$1,323	$1,361	$920 to $1,023	
Capital Cost Escalation Rate (%)	-2.46%					-1.50%					
Fixed O&M ($/kW-yr)	$0.00			$40.64	$25.26	$0.00		$15.00	$15.54	$9.2 to $12.3	
Variable O&M ($/MWh)	$0.00			$0.00	$0.00	$0.00			$0.00	$0.00	
Levelized Cost of Energy ($/MWh)		$271.12	$157.10	$183.25			$39.57			$31.7 to $40.9	$50.49
Average Heat Rate (MBTU/MWH)											
EFOR	0%										

Resource Type	ICT Frame (2x)[5]						ICT Aero (2x)				
Forcast Source	DESC	VP 2020 IRP	KP 2019 IRP	SWEPCO 2019 IRP	EIA AEO 2020	Lazard's 2019	DESC	VP 2020 IRP	KP 2019 IRP	SWEPCO 2019 IRP	EIA AEO 2020
Capacity (MW)	523		490	490	237	50 to 240	131		120	120	105
Capital Cost ($/kW)	$469	$562	$700	$730	$726	$715 to $972	$918	$1,107	$1,100	$1,459	$1,197
Capital Cost Escalation Rate (%)	3.75%						3.75%				
Fixed O&M ($/kW-yr)	$5.66			$16.44	$7.13	$5.62 to $21.22	$12.11			$19.73	$16.60
Variable O&M ($/MWh)	$0.34			$6.33	$4.58	$4.86 to $6.39	$0.34			$2.54	$4.79
Levelized Cost of Energy ($/MWh)		$138.13	$117.20	$118.83		$153.4 to $203.5		$198.63	$135.70	$149.89	
Average Heat Rate (MBTU/MWH)	9364	9670		10000	9905	8,000 to 9,804	9131	9320		9900	9124
EFOR	5%						1%				

Resource Type	CC 1-on-1					
Forcast Source	DESC	VP 2020 IRP	KP 2019 IRP	SWEPCO 2019 IRP	EIA AEO 2020	Lazard's 2019
Capacity (MW)	553		610	540	418	550
Capital Cost ($/kW)	$1,330	$1,492	$900	$1,042	$1,104	$716 to $1,330
Capital Cost Escalation Rate (%)	3.75%					
Fixed O&M ($/kW-yr)	$8.81			$11.27	$14.36	$11.2 to $13.8
Variable O&M ($/MWh)	$0.34			$2.05	$2.60	$3.1 to $3.8
Levelized Cost of Energy ($/MWh)		$77.05	$60.20	$64.94		$45.0 to $69.5
Average Heat Rate (MBTU/MWH)	6300	6630		6300	6431	6,133 to 6,900
EFOR	5%					

Notes:

(1) Battery capacity includes 4 hour duration.
(2) AEO 2020 only has Solar Photovoltaic with Tracking.
(3) Levelized Cost of Energy includes tax subsidies.
(4) Variable cost includes value for RECs.
(5) Represent Different Combustion Turbine Frame technologies between utilities.

DESC's capacity assumptions for the six (6) resource options appear to be reasonable compared to the other sources of information, and while the Company assumes a much higher capacity for the BESS resources than other utility IRPs and other sources, 100 MW battery systems do exist,[79] and Florida Power & Light Company has announced it will build an even larger BESS resource at 400 MW, which it projects will be online in 2021.[80]

DESC's owned solar and BESS overnight capital cost assumptions appear to be reasonable when compared to other utilities and are around the midpoint of all capital cost assumptions sampled. However, the Company's assumption that the capital costs for these resources will continue to decline throughout the next thirty (30) years while the capital costs for any natural gas-fired resource will continue to escalate is questionable. According to Table 18 on page 62 of Exhibit 2 to Mr. Bell's Direct Testimony, by 2040 this will lead to the overnight capital costs of solar dropping to $851/kW while the overnight capital cost of combined cycle units, which currently provide more generation than any other technology in the United States,[81] will more than double to $2,777/kW. This disparity becomes even greater by the end of the modeling period in 2049. While commodity prices and technological advances may continue to reduce the price of solar and battery technologies, it would be more appropriate for DESC to only apply the de-escalation of overnight capital costs for a shorter fixed period of time rather than for the entire study period.

DESC's overnight capital cost assumption of $469/kW for its ICT resource appears to be quite low compared to the other ICTs in the table and could potentially bias results in favor of ICT alternatives, although the Company's ICT estimate is not significantly lower than Virginia Electric and Power Company's ICT estimate. DESC's capital cost estimate for its ICT aero option and its CC option appear reasonable compared to the other sources.

With regard to variable and fixed O&M, the Company did not model any variable or fixed O&M expense for the battery storage and utility solar units, which is not reasonable and should be corrected in future resource planning analyses. The Company's variable O&M assumptions also are questionable for all CC and ICT options that were modeled, as the Company includes a variable O&M expense of $0.34/MWh. The Company's variable O&M expenses for CC and ICT options are a fraction (less than one-sixth) of the variable O&M expense assumed by other utilities in their IRPs. The Company's fixed O&M

[79] https://www.tesla.com/blog/tesla-powerpack-enable-large-scale-sustainable-energy-south-australia
[80] https://www.powermag.com/fpl-will-build-worlds-largest-battery-storage-system/
[81] https://www.eia.gov/energyexplained/electricity/electricity-in-the-us-generation-capacity-and-sales.php

expenses for its CC and ICT resources appear to be low, though they do not appear to be completely unreasonable compared to the other sources.

In other IRPs reviewed, lower variable O&M expenses are offset by greater fixed O&M expense. However, in the DESC IRP, the fixed O&M expenses for its generic CC and ICT resources also are lower than most of the fixed O&M expenses assumed by other utilities in their IRPs.

For generic CC and ICT resources, the average heat rate characteristics appear to be reasonable when compared to the other sources.

Finally, while there are no Solar PPA cost comparisons shown in the table, recent research conducted by the Lawrence Berkeley National Lab ("LBNL") provides insight into solar PPA costs.:[82]

> Driven by lower installed project prices and, at least through 2013, improving capacity factors, levelized PPA prices for utility-scale PV have fallen dramatically over time, by $10/MWh per year in most years since 2013. Most recent PPAs in our sample—including many outside of California and the Southwest—are priced below $40/MWh levelized (in real 2018 dollars), with many priced below $30/MWh and a few even priced below $20/MWh. Despite these low PPA prices, solar continues to face stiff competition from both wind and natural gas. Excluding the benefit of the 30% ITC, the median LCOE among operational PV projects in our sample stood at $53.8/MWh in 2018, and has followed PPA prices lower over time, suggesting a relatively competitive market for PPAs.

From Table 11 above, DESC's price for solar PPAs, $50.49/MWH appears to be consistent with the LBNL assessment, based on an assumption of no ITC. However, since the current tax law permits 10% ITC, the Company should revise its capital cost revenue requirement assumption to include the 10% ITC in corrections and revisions to its IRP in this proceeding and also in future IRPs.

Although it is not listed as a generic resource option by the Company, the Company assumes that it can purchase short-term capacity to meet its winter peak load in its resource planning. This capacity purchase is effectively a generic resource. The purchases have an assumed heat rate of 12.7 MBTU/MWH, a natural gas fuel price, an

[82] LBNL 2019 Utility Scale Solar Report, https://emp.lbl.gov/sites/default/files/lbnl_utility_scale_solar_2019_edition_final.pdf

energy cost adder of $4.05/MWH, and a capacity price of $4.50/kW-month, which it did not escalate in future years.

Although it is not inappropriate for a utility to include capacity purchases in its IRP or to actually make capacity purchases, DESC does not rely on an economic process in deciding to add these units, it simply uses an automatic decision-making process. This is not consistent with typical resource planning, which attempts to add resources to meet a reserve margin criterion, but based on resource availability and at the least cost. In the future, the Company should employ an economic decision making process in deciding whether to add short term capacity purchases or some other type of resource in its IRP. In addition, if capacity purchases are modeled in the future, the Company should account for escalation in the cost of the resource just as it does for the other resource additions it models.

Generic Resource Options Recommendations

1. The Company should review its assumptions regarding long-term continuing capital cost de-escalation of renewable energy projects. It is unlikely that capital costs of solar and BESS resources will see continued annual declines over the next 30 or more years.
2. The Company should review its capital cost assumptions for its ICT resource in this IRP to ensure that the costs are reasonable given its assumption appears to be much lower than other industry estimates.
3. The Company should include fixed O&M expenses for new owned solar and BESS resource additions in this and future IRPs.
4. The Company should review its O&M expense assumptions for all CC and ICT options and revise those assumptions in this IRP to the extent they are unreasonable or in error. It is not reasonable that two different types of ICT resources and a CC resource would incur the same variable O&M expense of $0.34/MWh. Not only is it unreasonable to expect they would incur the same variable O&M expense, but that value appears to be significantly lower than values from other industry sources.
5. The Company should reevaluate its assumption regarding its reliance on generic winter capacity purchases and ensure that any decision to add those capacity purchases is made based on the availability and economics of the capacity purchases.

Resource Planning

Overview of Resource Plans

The Company did not utilize a generation resource optimization planning tool to select the new resources and the timing of the new resource additions to produce the least cost RP for different sensitivity cases based on the generic resource options and other constraints.[83]

Instead, the Company developed eight (8) specific resource plans that reflect variations in the type and timing of potential new resource additions, including natural gas-fired ICTs, natural gas-fired CCs, owned solar facilities, solar PPAs, solar PPAs with BESS, and stand-alone BESS.

This approach limited the resource planning analyses to only those eight (8) RPs confected by the Company and the related sensitivities. There may be a lower cost RP than any of the eight RPs presented.

Certain of the RPs reflect continued operation of the Company’s existing generating units with no early retirements. Others reflect the potential early retirement of one or both of the Wateree coal-fired generating units, the Williams coal-fired generating unit, the McMeekin natural gas-fired steam generating units and the Urquhart 3 natural gas-fired steam generating unit.

Using its eight RPs, the Company initially compared low, medium and high DSM assumptions, $0 per ton CO_2, and base gas prices to evaluate the results of the RPs. The Company also performed various sensitivities against the eight RPs to reflect $25 per ton CO_2 assumptions, and low and high natural gas price assumptions.

In addition to the eight (8) RPs and sensitivities for each of those RPs, the Company developed five additional RPs using assumptions provided by the SCSBA. The SCSBA RPs reflect alternative DSM assumptions, alternative timing of new resource additions, and lower new solar and battery resource costs. The Company does not consider the SCSBA RPs as viable alternatives for its planning purposes due to the low capital cost assumptions for solar resources specified for these RPs. The Company also claimed that some of the SCSBA cases that had DSM assumptions that likely were not achievable.[84]

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83 ORS AIR 1-20.
84 IRP Report, Appendix A pg. A-3.

Each of the RPs in the Company's filing incorporates the results of multiple analyses, including the development of a portfolio of existing and new resources (expansion plan) to meet the peak load requirements, production cost modeling, incremental costs and revenue requirements for new resources additions, and an incremental economic analysis to derive the RP comparisons and rankings.

Summary of Resource Plan Retirements and Additions

The Company provided a description of each of the eight (8) RPs, which are replicated below for ease of reference in the subsequent description of the Company's modeling and the concerns identified by ORS.

RP1 ("CC"): In this resource plan a 553 MW (winter capacity) combined cycle gas generator is added when the winter reserve margin drops below 14%. 523 MW blocks of ICTs are added to maintain the 14% winter reserve margin during the modeling period.

RP2 ("ICT"): In this resource plan 523 MW (winter capacity) of ICT gas generators are added when the winter reserve margin drops below 14% during the modeling period.

RP3 ("Retire Wateree"): In this resource plan Wateree units 1 and 2 are retired in 2028 and a combined cycle gas generator is added in 2028. Five hundred twenty-three (523) MW of ICTs are added to maintain the 14% winter reserve margin during the modeling period.

RP4 ("Retire McMeekin"): In this resource plan McMeekin 1 and 2 along with Urquhart 3 are retired in 2028. Their 346 MW of capacity are replaced by 523 MW of ICT capacity. Five hundred twenty-three (523) MW of ICTs are added to maintain the 14% winter reserve margin during the modeling period.

RP5 ("Solar + Storage"): In this resource plan 400 MW of Company owned flexible solar generation plus 100 MW of battery storage are added in 2026. The next increment of capacity necessary to maintain a 14% winter reserve margin is a 553 MW combined cycle gas generator. After the CC, 523 MW of ICTs are added to maintain the 14% winter reserve margin during the modeling period.

RP6 ("Solar"): In this resource plan 400 MW of Company owned flexible solar generation is added in 2026. Five hundred twenty-three (523) MW of ICTs are added to maintain the 14% winter reserve margin during the modeling period.

RP7 ("Solar PPA + Storage"): In this resource plan 400 MW of flexible solar PPA generation plus 100 MW of battery storage are added in 2026. Five hundred twenty-three (523) MW of ICTs are added to maintain the 14% winter reserve margin during the modeling period.

RP8 ("Retire Coal"): In this resource plan Wateree and Williams are retired in 2028 and replaced with a 553 MW 1-on-1 combined cycle plant and 523 MW of ICTs. Dual fuel capability is eliminated at Cope, so Cope burns only natural gas starting in 2030. Additional tranches of 100 MW of battery storage and 131 MW ICTs are added to maintain the 14% winter reserve margin during the modeling period. Solar is added each year from 2029 to 2048. This resource plan is the low carbon plan.

Evaluation of Resource Plans

The eight (8) RPs reflect new resource additions necessary to maintain the Company's reserve margin planning targets throughout the study period. For modeling purposes, winter capacity purchases were assumed to be short term purchases of peaking resources from a neighboring utility.

In addition, the Company's RPs were constrained so that there will be no new CC or ICT resource additions prior to 2035, except in the RPs that incorporate early retirements of existing coal and natural gas resources. An optimization model would determine not only the optimal type of resource addition, but also the optimal timing of those additions.

The Company plans to utilize an optimization model in the future. In response to ORS discovery, the Company states that implementation of the Plexos optimization model is in progress and if successful, it will be used for the 2021 IRP.[85]

Even without the use of a least cost optimization model, the Company could have evaluated more than eight (8) RPs in its IRP. In comparison to this IRP, the Company evaluated more than double the number of RPs in the 2019 IRP (eight (8) compared to nineteen (19)).

The Company's approach to developing resource plans fixed the resources for eight cases under low, moderate and high DSM assumptions (twenty-four (24) cases in total). The Company also evaluated high and low gas price forecasts and an alternative CO2 case as sensitivity cases, but it did not change the RPs for those cases. It is unlikely that the Company's expansion plan in a future, for example, with no CO_2 would turn out to be identical to its expansion plan in a future with CO_2.

[85] ORS AIR 5-13.

The Company did not conduct a comprehensive retirement study to determine the economic retirement dates for its older coal-fired and gas-fired steam or its ICTs prior to the development of its RPs, although it conducted limited Wateree 2 repair or retire analyses and it considered early retirements of its coal-fired and certain natural gas-fired resources in some of its RPs.[86] It should be noted that the Company simply relied on the probable retirement dates from its most recent depreciation study without performing any further engineering or economic analyses. The Company acknowledges that its retirement analyses were limited and that the RPs do not include all costs that would be incurred if it retired its coal-fired and certain natural gas-fired resources prior to or at their current probable retirement dates. In a comprehensive retirement study, the Company would address the timing of retirements for each existing coal-fired and gas-fired resource, need for and timing of new resources, type and size of new resources, availability of natural gas to supply new CC and ICT resources, fuel cost sensitivities, incremental transmission costs for voltage support, and reliability impacts.

The Company's IRP does not discuss the Wateree 2 outage, which occurred shortly before this IRP filing was made. However, a decision about what to do with the unit should be addressed and justified in the Company's IRP. In addition, the Company also should address what it intends to do to replace the 342 MW of Wateree 2 capacity during the two year repair period until it is returned to service. Furthermore, an RP developed subsequent to the IRP indicates that a different new resource addition should be made in the 2035 time period.

Finally, while the Company provided results of some of its IRP analyses, it did not include tables with the results of the low and high DSM with $25 per ton CO_2 price sensitivities and the low and high natural gas price sensitivities in the IRP.

<u>Resource Planning Recommendations</u>

1. The Company should place a high priority on completing implementation of the least cost optimization model by the 2021 IRP Update.

2. The Company should expand the number of RPs evaluated for future IRP filings.

3. The Company should escalate its cost assumptions for short-term winter capacity purchases.

[86] ORS AIRs 1-15 and 6-4.

4. The Company should update its IRP to include tables that rank all RPs under all sensitivities.

Company's Evaluation and Ranking of RPs Based on Various Revenue Requirement Metrics

The Company compared RPs based on various metrics including the least cost levelized annual revenue requirement over forty (40) years, the net present value of the fuel costs, and the level of CO_2 emissions. It then identified the least cost resource plan based on the levelized annual net present value. The Company determined that RP2 was the least cost RP under all DSM sensitivities when the gas price and CO_2 price forecasts were set to base gas and zero CO_2 assumptions, respectively. The Company also found that RP2 was the least cost RP in two (2) cases where the DSM was set to the Medium case, and natural gas prices and CO_2 prices were varied. Those cases were the zero CO2, low and base gas cases.

In cases with either high gas prices or high CO_2 prices ($25 per ton), either RP7 or RP8 was the least cost RP. These RPs include more renewable resources than RP2 in response to the high gas price and CO_2 price assumptions. These RPs also assume there will be no reliability issues associated with adding intermittent renewable resources, which is unlikely without modifications to the transmission system and changes to the operation of its generating resources, including maintaining higher operating reserves.

Table 12 provides a comparison of the RPs as modeled by the Company on a cumulative net present value basis over forty (40) years assuming medium DSM, $0 per ton CO_2, and base gas prices. The least cost as modeled by the Company is RP2.

Table 12

Resource Plan Cumulative NPV at End of 40 Years for Medium DSM ($M)

Resource Plan ID	Resource Plan Name	$0/ton CO_2, Low Gas	$0/ton CO_2, Base Gas	$0/ton CO_2, High Gas	$25/ton CO_2, Low Gas	$25/ton CO_2, Base Gas	$25/ton CO_2, High Gas
RP1	CC	$13,202	$14,137	$16,155	$15,679	$16,630	$18,884
RP2	ICT	$12,964	$13,939	$16,029	$15,515	$16,543	$18,850
RP3	Retire Wateree	$13,187	$14,159	$16,348	$15,532	$16,527	$18,863
RP4	Retire McMeekin	$13,062	$14,031	$16,134	$15,622	$16,639	$18,961
RP5	Solar + Storage	$13,423	$14,336	$16,242	$15,782	$16,704	$18,891
RP6	Solar	$13,167	$14,103	$16,111	$15,607	$16,589	$18,855
RP7	Solar PPA + Storage	$13,070	$13,994	$15,998	$15,505	$16,475	$18,728
RP8	Retire Coal	$13,397	$14,346	$16,608	$15,348	$16,282	$18,630

Table 13 provides a comparison of the RPs as modeled by the Company on a levelized annual basis over forty (40) years assuming medium DSM, \$0 per ton CO_2, and base gas prices. The least cost as modeled by the Company is RP2.

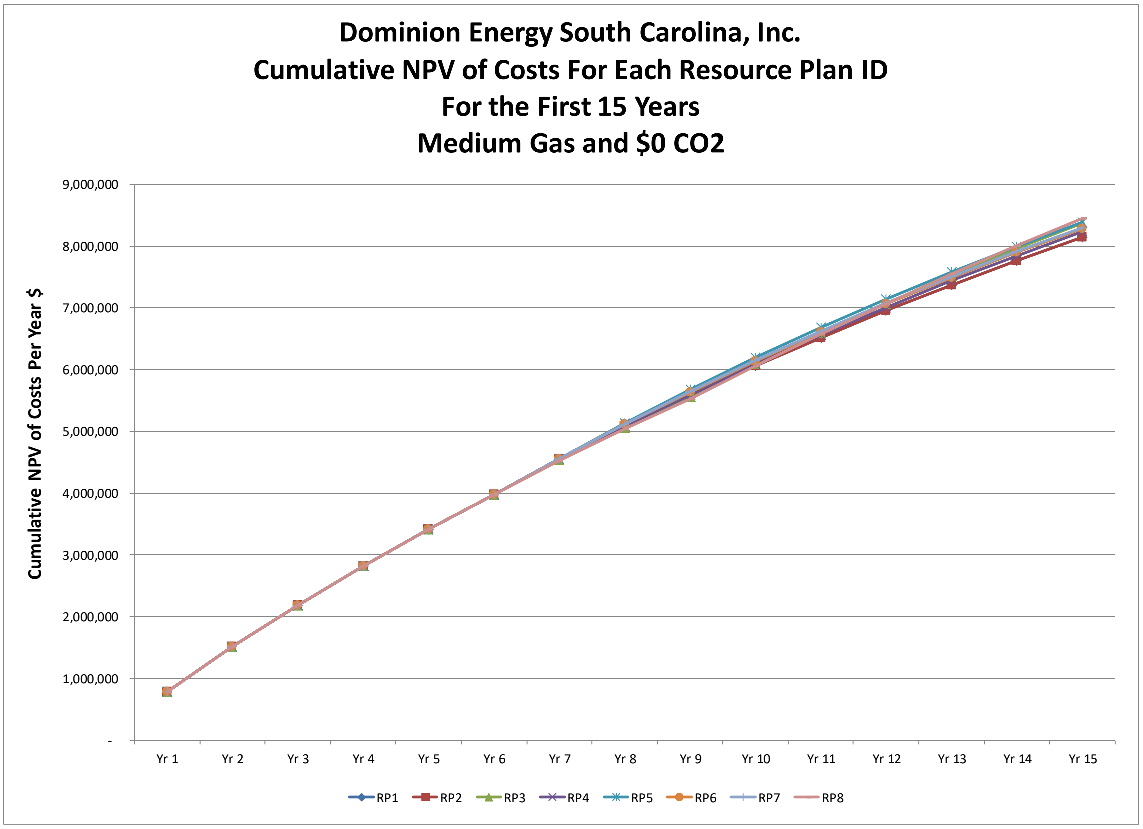
Table 13

Resource Plan Levelized NPV for Medium DSM ($M)

Resource Plan ID	Resource Plan Name	\$0/ton CO_2, Low Gas	\$0/ton CO_2, Base Gas	\$0/ton CO_2, High Gas	\$25/ton CO_2, Low Gas	\$25/ton CO_2, Base Gas	\$25/ton CO_2, High Gas
RP1	CC	\$1,167	\$1,249	\$1,427	\$1,385	\$1,469	\$1,669
RP2	ICT	\$1,146	\$1,232	\$1,416	\$1,371	\$1,462	\$1,666
RP3	Retire Wateree	\$1,165	\$1,251	\$1,445	\$1,372	\$1,460	\$1,667
RP4	Retire McMeekin	\$1,154	\$1,240	\$1,426	\$1,380	\$1,470	\$1,675
RP5	Solar + Storage	\$1,186	\$1,267	\$1,435	\$1,395	\$1,476	\$1,669
RP6	Solar	\$1,163	\$1,246	\$1,424	\$1,379	\$1,466	\$1,666
RP7	Solar PPA + Storage	\$1,155	\$1,237	\$1,414	\$1,370	\$1,456	\$1,655
RP8	Retire Coal	\$1,184	\$1,268	\$1,467	\$1,356	\$1,439	\$1,646

The following graph provides a comparison of the RPs on a cumulative net present value basis for the first fifteen (15) years assuming medium DSM, \$0 per ton CO_2, and base gas prices. The cumulative net present value is virtually the same among all eight (8) RPs from 2020 through 2027 and begins to diverge in 2028 due to differences in whether the Wateree generating units are retired in 2028 or earlier and differences in new resource additions starting in 2028 and in later years.

Figure 8



The RPs also can be compared on a nominal dollar basis, either on a cumulative nominal dollar basis or on an annual nominal dollar basis. These revenue requirement metrics are not a substitute for the net present value metrics or the determination of the least cost based on those metrics, but are used to assess the annual rate effects of each RP, which could be a factor if there are significant rate increases in any year or over a few years under the least cost RP or any alternative RPs that may not be least cost, but nevertheless are under consideration for other reasons. For example, RP5 reflects a significant increase in the annual revenue requirements starting in year seven (7) if the Wateree units are retired in 2028 and replaced with owned solar and battery storage.

The following graphs provide a comparison of the RPs on a cumulative nominal dollar basis and annual nominal dollar basis for the first fifteen (15) years assuming medium DSM, $0 per ton CO_2, and base gas prices.

Figure 9

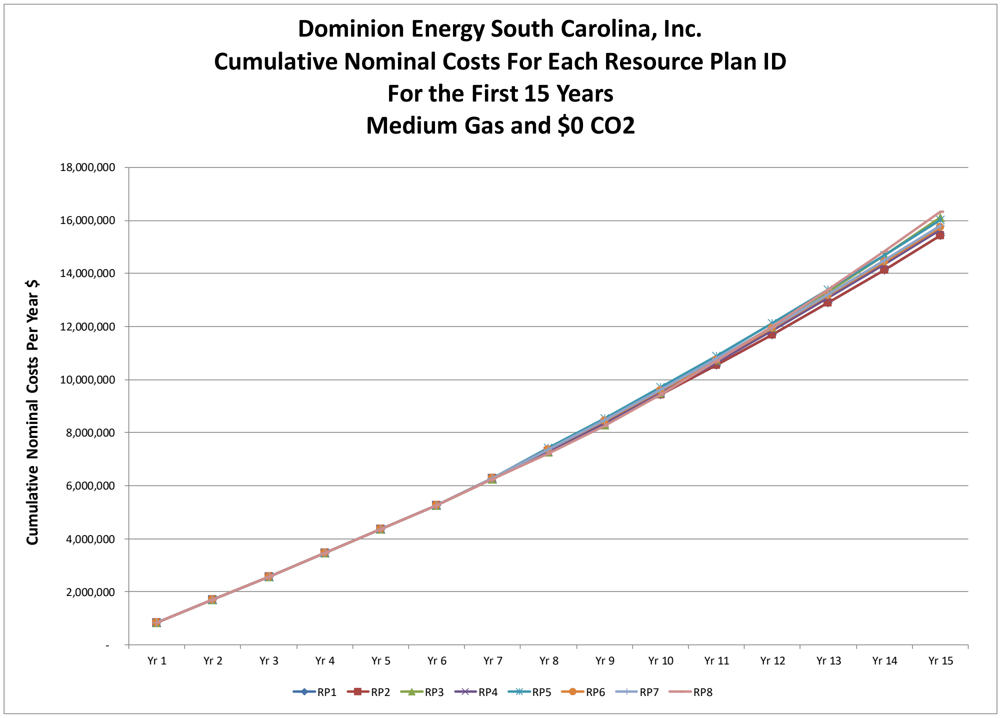
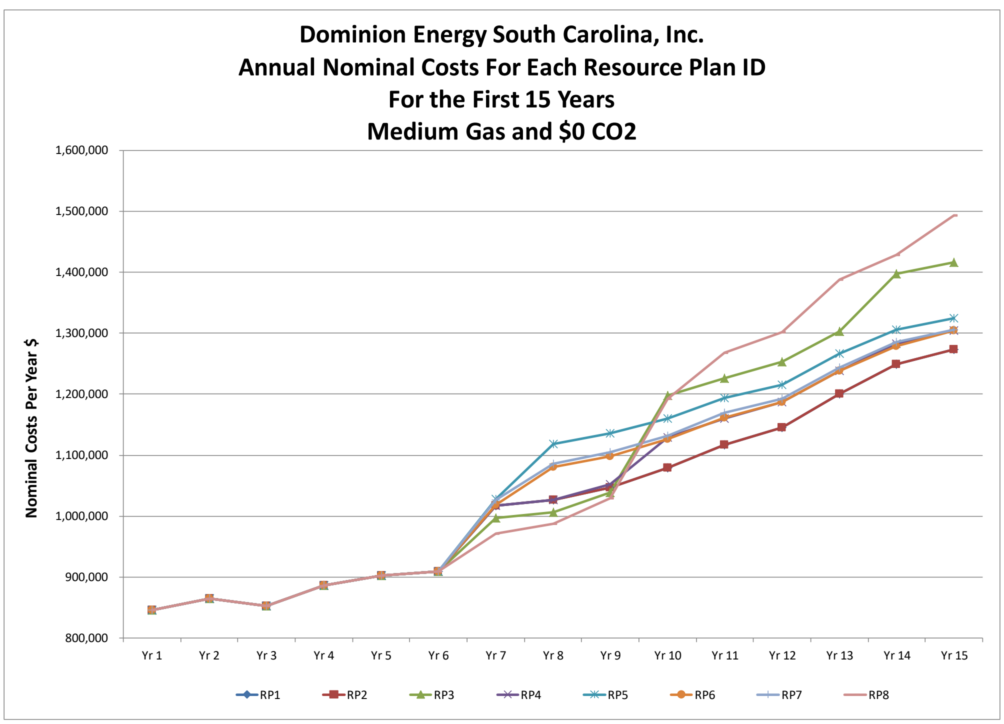


Figure 10



Critique of Company's RP Modeling

The validity of the Company's RP modeling depends on the analytical framework, including the validity of the assumptions and accuracy of the calculations used to develop the costs reflected in the annual revenue requirements that are, in turn, used to compare the RPs to determine the least cost plan. The results of the Company's RPs are tightly clustered. The modeling steps that led to these results include the PROSYM results and the capital revenue requirements, which were combined to determine the annual revenue requirements and provided the basis for the economic comparisons and rankings.

PROSYM Modeling of the Resource Plans

The Company's PROSYM production cost modeling runs were designed to determine fuel and purchase power costs for the DESC system for each RP case over the study period, accounting for all changes to the RP case's expansion plan. The production cost modeling reflects the operation of all existing and new resources in meeting the DESC load requirements after adjustments for the implementation of the DSM and energy efficiency programs recently approved by the Commission. Adjustments to modeling characteristics were made to account for impacts of making wastewater treatment upgrades for effluent from flue gas desulfurization systems at the Wateree and Williams to comply with the EPA's ELG.

The Company used PROSYM to calculate the annual variable and fixed fuel expenses, and other variable and fixed O&M expenses included in the production costs for each RP. The Company used an Excel workbook to forecast and calculate the nominal dollar annual revenue requirements for each RP and sensitivity case, which include the fuel and non-fuel O&M expenses and the incremental capital-related revenue requirements for all new resource additions as well as the ELG capital expenditures/plant additions for Wateree and Williams. In those Excel workbooks, the Company also calculated the net present value of the forecast annual revenue requirements on a levelized (annuitized) annual basis. It then compared and ranked the RPs based on various metrics.

PROSYM is a chronological hourly probabilistic production cost model. The PROSYM model dispatches the system's generating resources to meet hourly system loads similar to the way a power system dispatcher would in actual system operations. As part of the dispatch process, PROSYM considers operational constraints, such as minimum up and downtimes, random forced outages and transmission transfer limits. It is designed to determine the station generation, emissions, fuel, purchase and sales costs, variable and fixed fuel costs, variable and fixed operating and maintenance costs, for each hour in the simulation period.

PROSYM is not an optimal expansion modeling tool. PROSYM calculates the production costs under a specified RP. In contrast, an optimal expansion planning model automatically sets up and tests potentially hundreds or thousands of RP alternatives to identify the least cost RPs under various assumptions and sensitivities.

PROSYM requires numerous data inputs, which include the forecast loads and hourly load profiles; operating characteristics of each existing generating unit, generally based on historic performance and adjusted for forecast changes; operating characteristics of each new resource; forecast fuel costs per MMBtu, including delivered coal costs and delivered natural gas costs; transmission import and export capabilities and external pricing for purchases and sales; and other data necessary to accurately simulate the operation of the system in future years.

ORS has concerns regarding some of the modeling assumptions made by the Company. The Company fails to model any costs at all for the generic BESS resources and utility owned solar resources, although it says this error will be corrected in future IRPs.[87] In addition, all BESS resources stay active in PROSYM for the entirety of the study period instead of for their assumed ten (10) year operating life, producing free energy and understating costs in resource plans that include BESS.

Another issue is the fact that the Company models all incremental ICT additions as one distinct unit in the PROSYM model, which overstates any reliability concerns regarding the units forced outage rate. This is due to all generic ICT additions sharing one outage rate; in practice, an outage at one ICT would not necessarily cause outages at other ICT facilities.

Finally, for the 400 MW flexible solar PPA assumption, the company models a fixed price in PROSYM every year. Solar PPAs are typically purchased on a $/MWh basis, yet while the generic flexible solar PPA units have different generation in each production cost run, there is a fixed cost applied to the unit every year.

Excel Workbook Modeling of The Resource Plans

The Excel workbook includes not only the annual expenses resulting from the PROSYM modeling, but also the revenue requirements due to capital expenditures from resource additions and the capital expenditures/plant additions necessary to comply with the ELG requirements at the Wateree plant if both units are not retired in 2028 and the Williams plant if it is not retired in 2028. This results in a calculation of the annual nominal revenue requirements for each of the RPs and sensitivities. In the final step, the Excel workbook

[87] ORS AIR 7-2a and ORS AIR 7-6

calculates the levelized annual revenue requirement, which the Company used to summarize and rank the RPs in the Plan Report.

The Excel workbook reflects the assumptions for new generic resource additions, including timing, type, size, capital cost, service life, rate of return, income tax rate, property tax rate, insurance rate, Commission assessment rate, and decommissioning rate (nuclear only). The Company developed these assumptions for ICTs (523 MW units or 131 MW aeroderivative units in later years), CCs (553 MW), owned solar (50 MW in early years, then 100 MW), owned solar with BESS (battery 100 MW), solar PPAs (400 MW), and solar PPAs with BESS. The Company developed assumptions regarding the transmission integration costs for new generic resource additions and included these costs in the capital expenditures for the owned new resource additions. It also developed assumptions regarding the cost of new gas infrastructure for the CC resources and included these costs in the fixed O&M expense. The Company failed to include similar costs for the ICTs, although it did so in the Wateree studies that were performed since the IRP was filed.

The Company calculated overnight capital costs for the new generic resource additions based on future dollar cost estimates obtained from Dominion Energy Services – Generation Construction Financial Management & Controls de-escalated to current dollars. The Company then re-escalated those overnight capital costs in current dollars to future dollars based on the year the capital expenditures were made for each new resource. The escalation rates vary by type of resource. The Company calculated the annual capital expenditures based on construction "cash" spend curves for each new resource. The cash spend curves also vary by type of resource.

The Excel workbooks for the RPs incorporate numerous errors, both conceptual errors, due primarily to errors in assumptions and errors of omission, and practical or calculation errors, due primarily to ministerial or mechanical errors in data inputs and other data and/or formula errors used in the calculations, and . The most significant of these errors are as follows, including recommendations on correcting the errors.

1. PROSYM Production Expenses Incorrectly Transferred to Excel Models

There were errors in the transfer of PROSYM production costs to the Excel models. This resulted in incorrect annual revenue requirements, which misstated the levelized net present value of the RPs and sensitivities, as well as the SCSBA RPs and sensitivities. In the first error, the Company included the cost of emergency energy determined in the PROSYM modeling twice, i.e., it was double counted in the revenue requirement calculations used to rank the RPs. Emergency energy ranged from less than $0.1 million in some years to as much as $3 million in one year.

In another error, the Company failed to include the fixed fuel expense associated with coal at the dual fuel Cope Station in the PROSYM costs transferred to the Excel model, so that this expense was not included in the annual revenue requirements or the levelized net present value in the RPs where the Company operated the Cope Station in the dual fuel mode. This matters because the resource portfolio for RP8 was designed to evaluate the elimination of coal at the Cope station and for it to operate solely on natural gas. In RP8, it was appropriate when operating on natural gas for the coal fixed fuel cost to have been eliminated, however, for all other RPs, the Cope coal fixed fuel cost should have been included. For all of the cases in which it should have been included, the revenue requirements were understated by amounts ranging from approximately $7 million in 2030 to approximately $11 million in 2049.

In the repair, replace, or retire Wateree 2 analyses, the Company introduce yet another error. The costs of purchases and sales were not transferred from PROSYM to the Excel model and were not included in the annual revenue requirements or in the levelized net present value of the RPs.

Recommendation

The Company should correct all data transfer errors. It should include Cope Coal fixed fuel expense in all resource plans' revenue requirement models except for in RP8 after Cope is converted to only run on natural gas. It should correct the double count of emergency energy. It should include purchase and sales transactions when transferring results from PROSYM to the Excel model.

2. Installed Costs of New Resources Understated Due to Failure to Include Capitalized Interest (AFUDC).

The Company failed to include capitalized interest AFUDC in the capital costs of the new resources, despite the fact that it will finance these capital expenditures during the construction period.[88] The Company assumed that the new resources will be constructed over multiple years, not acquired from third-party developers on an overnight or turnkey

[88] Response to ORS 6-10(b). The Company confirmed that the overnight costs for the new resources do not include financing costs during construction. Also, response to ORS 1-22 Excel workbook "Generic IRP-SEG New Build_Working Copy" that is used to populate fields in the Excel workbook calculations for each RP and sensitivity, specifically the calculations of the fixed charge rates and the annual capital-related revenue requirements. In the "Generic IRP-SEG New Build" the annual capital expenditures are notated with the comment "capitalized interest not included."

(build own transfer) basis. The Company will be required to capitalize the financing costs as AFUDC pursuant to generally accepted accounting principles ("GAAP") and the FERC Uniform System of Accounts ("USOA").

This error understates the installed costs of the new resources and the annual revenue requirements for the return on the installed costs, less accumulated depreciation and ADIT, and the depreciation expense on the installed costs of the new resources each year after commercial operation, all else equal. Table 13 compares the installed cost a new CC resource addition in 2026 with and without AFUDC. The Company erroneously assumed the installed cost of the CC resource would not include AFUDC. If this error is corrected, the AFUDC adds $261/kW to the installed cost of a CC resource addition in 2025, all else equal. The error has the greatest effect on the installed costs of the new CC resource additions due to the magnitude of total construction cost and the duration of the construction period compared to the new ICT resource additions and new solar and battery resource additions, which are less capital intensive and have construction periods of shorter duration.

Table 14

Comparison of CC Installed Costs With and Without AFUDC

	1X1 CC	Base for Financing Costs	Financing Cost at 8.5%	Year End Cost Incl Fin
2020	$ 7,246	3,623	308	7,554
2021	$ 56,090	35,290	3,000	66,643
2022	$ 200,491	163,581	13,904	281,038
2023	$ 294,706	411,179	34,950	610,694
2024	$ 225,779	671,421	57,071	893,544
2025	$ 68,117	818,369	34,781	996,441
2026	$ -	$ -	$ -	996,441
	852,428		144,014	996,441
MW				553
Nominal Installed Cost ($/kW) No Financing Cost				1,541
Nominal Installed Cost ($/kW) With Financing Cost				1,802

Recommendation

The Company should correct this error by including financing costs for new resources in its revenue requirement Excel model for all resource plans analyzed.

3. Incremental Costs of New Resources And The Costs of Wateree and Williams for The ELG Capital Expenditures/Plant Additions Are Misstated Due to Errors in Calculations Affecting Escalation of Capital Expenditures to Future Dollars.

The Company's de-escalation of the installed cost in future dollars to 2019 dollars and subsequent escalation to the commercial operation dates for the new resource additions incorporate two errors, which partially offset each other in the calculation of the installed cost in future dollars subsequently used to calculate the annual capital-related revenue requirements. To derive the overnight (NPV) installed costs in 2019 dollars, the Company started with the installed costs in future dollars obtained from Dominion Energy Services – Generation Construction Financial Management & Controls that were based on estimated future commercial operation dates. Instead of de-escalating this *installed cost* in future dollars to 2019 dollars, the Company de-escalated the *annual capital expenditure* spend amounts to 2019 dollars. This has the effect of overstating the overnight costs in 2019 dollars due to fewer years of de-escalation based on the timing of the capital expenditures rather than the estimated commercial operation dates. The Company's model then escalates these overnight capital costs from 2019 dollars to the installed costs in future dollars based on the commercial operation dates for each new resource addition, but incorrectly assumed that the overnight costs were in 2020 dollars, not 2019 dollars.[89] This has the effect of understating the installed cost in future dollars due the loss of one year of escalation, assuming that the overnight costs were correctly calculated, which they were not.

<u>Recommendation</u>

The Company should correct this error in all resource plans by stating the installed cost of new resource additions and ELG capital expenditures in 2019 dollars.

4. Incremental Costs of Existing Resources And New Resources Are Understated Due to a Failure to Include Post-In Service Capital Expenditures/Plant Additions, Except for The Wateree and Williams ELG Capital Expenditures/Plant Additions.

[89] The Excel workbook "Generic IRP-New Build Working Copy" calculates the overnight cost in 2019 dollars. The Company shows the amounts in 2019 dollars as if they were 2020 dollars in its table titled "Description of Potential Resources" in the IRP Report at 39. It then used the 2019 dollars in the Excel workbooks for each RP and sensitivity to calculate the future dollar amounts, but assumed that the 2019 dollars were 2020 dollars.

The Company failed to include the incremental capital expenditures/plant additions for existing resources and for new resources after commercial operation, except for the incremental ELG capital expenditures on Wateree and Williams in those RPs where those plants continued to operate until their probable retirement dates. The revenue requirements due to incremental capital expenditures/plant additions are costs that will be incurred for each existing resource and each new resource and should be reflected in each RP. If significant, the failure to include these incremental costs could bias the ranking of the RPs based on the net present value of the cumulative revenue requirements or the levelized annual revenue requirements.

Recommendation

The Company should correct this error in all resource plans by including post-in service capital expenditures for new resources in their Excel revenue requirements models.

5. Cost of New Owned BESS Resources Are Understated Due to a Failure to Replace BESS Resources After Assumed 10 Year Operating Life.

The Company assumed that once it installed a new BESS resource, it would have a ten year operating life, which it properly reflected in the calculation of capital-related revenue requirements. However, it failed to reflect the "retirement" of each BESS resource at the end of its ten (10) year operating life in its expansion plan analysis and production cost modeling. In other words, at the end of the BESS operating life the Company simply assumed the BESS would continue to provide capacity and energy value to the system. Other than including degradation in the amount of energy that would be produced, the Company did not include any additional impacts to account for any replacement capacity or any refurbishment costs that would be necessary to keep the battery operating beyond its useful life. These errors are significant and understate the costs and annual revenue requirements for the BESS resources included in RP5, RP7, and RP8 and cause those RPs to rank higher compared to the other RPs with no new BESS resources, all else equal.

Note, this same problem is reflected in the five (5) SCSBA RPs, which understates the costs and annual revenue requirements for the new BESS resources in those RPs as well. The effect of this error is greater on the SCSBA RPs because of the greater new BESS resource additions compared to the BESS resource additions in the Company's RP5, RP7, and RP8.

Recommendation

The Company should correct this error by adding replacement capital costs or refurbishment costs for BESS resources at the end of the resource's assumed ten (10) year operating life.

6. Costs of New Owned Solar Resources And BESS Resources Are Understated Due to a Failure to Reflect Investment Tax Credit.

The Company failed to reflect the 10% federal investment tax credit as a reduction to the costs of new owned solar resources and BESS resources. This results in higher costs and annual revenue requirements for the new solar resources and BESS resources included in RP5, RP7, and RP8 and penalizes those RPs compared to the other RPs with no new solar resources and BESS resources, all else equal. Under the Internal Revenue Code (IRC) and related Treasury Regulations, the utility may elect to reflect either the "return on" or the "return of" (amortization) the ITC in utility rates, but not both. Under the return on election, the ITC is used to reduce the rate base in the same manner as ADIT is used to reduce rate base, and thus, reduces the return on rate base included in the annual revenue requirements. Under the return of (amortization) election, the ITC is amortized as a credit to income tax expense over the service lives of the new owned solar resources, and thus, reduces the annual revenue requirements in that manner.

It should be noted that the Company reflected the ITC in its calculation of the levelized cost per kWh for the flexible solar PPA resource included in RP7, although it failed to do so in the BESS resource addition in RP7.[90] In other words, it does not appear that the Company disagrees that the ITC is available for new solar resources, rather, it appears that the Company simply failed to incorporate the ITC in the cost of the new owned solar resources and new BESS resources. This is true not only for RP5, RP7, and RP8, and the sensitivities to those Company RPs, but also is true for the SCSBA RPs, which reflect more new solar resources than the Company's eight (8) RPs.

Recommendation

The Company should correct this error by calculating ITC for new Company owned BESS and Solar resources in the Excel revenue requirement workbooks of RP5, RP7, and RP8, as well as the SCSBA resource plans SB2, SB3, SB4, and SB5.

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[90] Response to ORS 1-22. The levelized price for this PPA was calculated in Excel workbook "Levelized Cost of Energy 2019_021020."

7. Cost of New Owned Solar and BESS Resources Are Understated Due to a Failure to Include Any O&M Expense.

The Company assumed that it would incur no O&M expense on the new solar or BESS resource additions. It is highly unlikely that the Company will not require any maintenance ever on these resource additions. It should be noted that this same problem is reflected in four (4) of the five (5) SCSBA RPs, which also understates the costs and annual revenue requirements for the new solar and BESS resources in those RPs. The effect of this error is greater on the SCSBA RPs because of the greater new solar and BESS resource additions compared to the solar and BESS resource additions in the Company's RPs.

Recommendation

The Company should correct this error by including appropriate O&M expenses in their PROSYM modeling of RP5, RP7, and RP8, as well as the SCSBA resource plans SB2, SB3, SB4, and SB5.

8. Incremental Costs to Retire Existing Resources Are Understated Due to a Failure to Include Dismantlement And Site Restoration Costs.

The Company failed to reflect the costs to retire existing resources in any of the RPs. Nearly all of its existing resources and certain of the new resource additions have probable retirement dates prior to 2060, the end of the forty (40) year period used to determine the levelized annual revenue requirement.[91] This error has greater effect in those RPs with premature retirements of existing coal-fired and natural gas-fired steam generating units. For example, the Company failed to reflect the costs to prematurely retire Wateree 1 and 2 in RP3, McMeekin 1 and 2 and Urquhart 3 in RP4, and Wateree and Williams in RP8. This results in lower costs and lower annual revenue requirements for these RPs compared to the other RPs, all else equal.

Recommendation

The Company should correct this error by including appropriate retirement costs for units which retire during the study period, for all Company RPs as well as all SCSBA resource plans.

[91] IRP Report at 33. This table provides a list of existing resources and the probable retirement dates for those resources.

9. Incremental Costs to Continue Operating Wateree and Williams Are Overstated Due to Incorrect Depreciable Life Assumption on ELG Capital Expenditures/Plant Additions.

The Company reflected an incorrect depreciable life assumption for the Wateree and Williams ELG capital expenditures, which start in 2026 in RP1, RP2, RP4, RP5, RP6, and RP7. This error overstates the fixed charge rate and the annual revenue requirements for these existing resources. Instead of using the remaining lives for these units based on the probable retirement dates of 2044 and 2047 for Wateree and Williams, respectively, the Company assumed that the service lives would be the same as for new ICT and CC resources. In the affected RPs, this error results in annual revenue requirements from 2026 through 2061 for both plants, or seventeen (17) years beyond the probable retirement date for Wateree and fourteen (14) years beyond the probable retirement date for Williams. If this error is corrected, the cumulative net present value in each of the affected RPs is reduced by $7,446,000.

<u>Recommendation</u>

The Company should correct this error by including the proper depreciable life for the ELG capital expenditures.

10. Incremental Costs of Gas Infrastructure for ICTs Were Not Included in Any of The RPs.

The Company's RPs all include additional ICT and/or CC capacity. The Company included pipeline costs in the fixed O&M expenses for the new CC resources, but failed to include such costs in the fixed O&M expenses for the new ICT resources. This error understates the costs of the addition of ICT resources in each RP. In fact, if this error is corrected in RP2, the least cost resource addition in 2035 is a CC resource, not an ICT resource.

<u>Recommendation</u>

The Company should include pipeline costs for new ICT resources in all RPs.

11. Incremental Cost of New Resource Addition in 2040 Was Not Included in RP8.

RP8 has thirty-four (34) new resource additions, consisting of solar, BESS, and ICT resources. However, the Excel workbook modeling for RP8 reflected only thirty-three (33) of those additions in the annual revenue requirements, even though all thirty-four (34) were included in the input section of the workbook. More specifically, the Excel workbook modeling for RP8 failed to include the capital-related revenue requirements for the aeroderivative ICT to be installed in 2040. This error understates the nominal annual revenue requirements starting in 2040 and the levelized annual revenue requirement for RP8.

Recommendation

The Company should include capital revenue requirements for the 2040 ICT resource in its analysis of RP8.

12. Extension of Production Costs for the Final 10 Years of the Study Period Used Inappropriate Escalation Factors.

The Company calculated escalation factors using a 3-year compound growth rate between 2046 and 2049 in order to extend fuel expense, variable O&M expense, fixed O&M expense, and other inputs from the production cost model for another ten (10) years through 2059. In all RPs except RP8, the Williams plant is retired in 2047; in RP8, the Williams plant is retired in 2028. In RP1 through RP7, the replacement generation is supplied from gas-fired generation, which is more expensive than the pre-retirement coal-fired generation formerly supplied by the Williams plant. This results in a one-time increase in fuel expense, all else equal. In addition, there is a reduction in fixed O&M expense when Williams is retired. This results in a one-time reduction in fixed O&M expense, all else equal. These one-time changes distort the results of the 3-year compound growth rates subsequently applied to calculate the fuel expense and fixed O&M expense in the final ten (10) years of the forty (40) year study period. As a result, the escalation rates do not produce reasonable estimates of these expenses in the final ten (10) years of the study period.

Recommendation

The Company should review its escalation modeling methodology in future IRPs.

13. Fixed Expansion Plans in CO_2 and Gas Price Sensitivity Cases.

The Company developed its resource plans and kept them fixed throughout gas price and CO_2 sensitivity analysis, utilizing capacity purchases (in some cases as much as 500 MW) in order to satisfy its reserve margin requirements. A distinct resource plan may be least cost in one gas price and CO_2 sensitivity, and require slight changes in timing or selection of resources to be least cost in another gas price and CO_2 sensitivity.

Recommendation

In future IRPs, the Company should develop alternative expansion plans for each gas price and CO_2 sensitivity in order to determine the most appropriate expansion plan for each scenario.

Transmission System Planning and Investment

The Company provided a summary description of its transmission planning process and a list of major planned transmission projects in Section III of the IRP report. The Company indicated the identified projects are being planned through early 2027 and were determined based on the Company's latest transmission assessment studies, though the Company stated that no commitment has yet been made to build these projects. The Company noted that the addition of intermittent resources, namely new solar resources, will require additional study to determine the impacts on the existing transmission system, the engineering design, physical changes, and investment necessary to meet these needs to provide reliable service.

The additional investment may be significant and the physical assets will need to be in operation to add significant new solar resources, especially under the RPs performed using assumptions provided by SCSBA. The Company continues to study these additional costs, but for purposes of the IRP, it incorporated only transmission interconnection costs in the capital expenditures/plant additions for new resource additions in the RPs, including those performed using assumptions provided by SCSBA. More specifically, the Company included transmission interconnection costs of $15.167/kW for new CC resources, $15.75/kW for new ICT resources, and $46.33/kW for new solar and BESS resources, all in 2020 dollars, which it then escalated by 3.45% to future dollars consistent with the timing of the new resource additions under the various RPs.

In its 2018 IRP filed with the North Carolina Utilities Commission, Dominion Energy North Carolina ("DENC") performed extensive studies regarding the transmission infrastructure investments that would be necessary to integrate large volumes of new solar resources on its system.[92] These studies included the identification of the potential solar sites in North Carolina and transmission studies that assumed 7,000 MW of new solar resources were added to DENC's system. DENC stated in its report to the NCUC the following:

[92] https://www.dominionenergy.com/library/domcom/media/about-us/making-energy/2018-irp.pdf, Section 5.1.3.1, Solar PV Integration Cost, at pg. 78.

> The results of a majority of these modeling cases identified several low voltage and thermal violations that would require mitigation activities via physical enhancements to the Company's transmission system. The total integration costs were then evaluated by including the cost of these enhancements with other required system interconnection costs. The results of this stochastic analysis are reflected in the total integration cost (interconnection plus transmission improvements) frequency distribution shown in Figure 5.1.3.1.1. Based on this analysis, the expected value of the total integration cost is approximately $165.00/kW.

DENC also stated that it derived different integration costs for solar resources connected at the transmission level versus at the distribution level, and it determined that integration costs should vary depending on how much solar resources have been already connected to its system. Ultimately DENC used an interconnection schedule that ranged between $75/kW and $155/kW, which is anywhere from 60% to 240% more than DESC's assumption in its IRP in this proceeding. In other words, the DENC studies suggest that the Company's transmission infrastructure costs for new resources, and more specifically, new solar resources, is significantly understated in this proceeding. If the DENC transmission costs are used, then this would increase the annual revenue requirements and the levelized annual revenue requirements for the RPs with new solar resources in the IRP, even more so for the RPs using assumptions provided by the SCSBA due to the greater magnitude of new solar resources.

Transmission System Planning and Investment Recommendations

1. ORS recommends that the Company complete the studies regarding the changes that will be necessary to the transmission system to add new solar resources, including the additional investment infrastructure costs, prior to its next comprehensive IRP in 2023 and include that information and a description of its studies and conclusions in that filing.

Distribution Resource and Integrated System Operations Plans

Section 40(B)(2) contains the provision that "An integrated resource plan may include distribution resource plans or integrated system operations plans." The Company discusses issues related to distribution resource plans throughout the IRP. For example, in the Executive Summary, the Company states that the:[93]

[93] IRP Report, Executive Summary, at pg. 1.

> IRP reflects DESC's commitment to clean energy in the energy efficiency programs offered to customers and in the probable modifications to the Company's electric transmission and distribution grid which will facilitate the growth of clean energy solutions while assuring that energy continues to be provided in a safe, reliable, and affordable manner.

Throughout the report, the Company notes the types of changes that will need to be made to its system such as the need to "upgrade its electric system through measures such as rolling out Advanced Metering Infrastructure ("AMI")..." The Company elaborates further on its AMI initiative in a section entitled, Distribution Resource Plan, in which it states that it is in the early implementation phase and currently has approximately 30,000 AMI meters installed and over time will increase the count to over 765,000 AMI meters in its service territory.[94]

The Company also notes throughout the report that in order to increase levels of renewable resources on its system, it will need to perform studies and conduct research to be able to accommodate the additional renewables and to ensure its system remains reliable. ORS agrees with the Company's desire to perform additional research and conduct further studies to properly assess the impacts of more renewable resources, as well as to plan for other emerging solutions and resources including advanced non-wires transmission and distribution alternatives, increased levels of electric vehicles ("EV"), installation of distributed energy resources ("DERs"), the use of energy storage, etc.

Other utilities are wrestling with these issues and some are beginning to implement processes that attempt to optimize capacity and energy resource investments across generation, transmission, distribution, and customer solutions. Duke Energy for example, has begun a stakeholder process to further involve its customers in its study of an Integrated System and Operations Planning ("ISOP") process. Duke Energy began this process in 2019 and plans to implement the basic elements of its plan and to discuss them in its 2022 IRP.[95] Duke Energy's vision is that it will leverage the benefits of its ISOP planning process in the period beyond 2022, which it notes aligns well with the fact that renewable resources and BESS will continue to become more competitive through that time.[96]

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[94] IRP Report, Section II.B.2, at pg. 25.
[95] https://www.duke-energy.com/our-company/isop
[96] https://www.duke-energy.com/_/media/pdfs/our-company/200062/duke-energy-isop-stakeholder-workshop-1.pdf?la=en at pg. 40.

The Company has addressed issues regarding the increased use of renewable resources, EVs, AMI, etc., in its IRP Report. It would be beneficial for the Company to provide more in-depth information in future IRP reports, such as to explain the kinds of efforts and schedules for rolling out programs such as AMI that it is involved in, discuss the kinds of obstacles it has to overcome, provide information about studies it plans to perform, and discuss whether it is planning to implement any type of integrated planning approaches that include generation resources, transmission, distribution and products and services.

Distribution and Integrated System Operations Plan Recommendation

1. The Company should supply additional information about distribution resource plans or integrated system operational plans. While the Company has complied with Section 40(B)(2), ORS recommends that the Company provide more details concerning this topic in future IRPs.

Other Considerations

It has been an increasing trend in the industry to incorporate more stakeholder involvement in the utility's IRP process. This stakeholder involvement should begin before the final choice of the Company's assumptions have been set, and will allow stakeholders to have the opportunity to influence the decisions that affect the costs they will have to pay and the types of generation resources that will be used to serve their energy needs.

Stakeholder processes can range from being a simple process that just involves briefings between utilities and regulatory agencies to more elaborate processes that involve numerous stakeholder meetings. PacifiCorp, as an example, typically holds numerous stakeholder meetings in this IRP process. PacifiCorp explains the purpose of the process is to facilitate information sharing, collaboration, and to set expectations for the IRP, and it also states, "The topics covered all facets of the IRP process, ranging from specific input assumptions to the portfolio modeling and risk analysis strategies employed."[97]

The Company should facilitate a stakeholder process to achieve some of the same objectives, though ORS recognizes that care should be taken to ensure the process does not become overly burdensome. Two (2) other models to evaluate would be Duke Energy's stakeholder process, which is open to stakeholders in both North and South

[97] https://www.pacificorp.com/content/dam/pcorp/documents/en/pacificorp/energy/integrated-resource-plan/2019_IRP_Volume_I.pdf, Chapter 2 – Introduction, Public Input Process, at pg. 31.

Carolina. The other would be in Louisiana, in which the Louisiana Commission requires each utility to include two (2) stakeholder meetings as part of its IRP process, which afford parties a chance to interact and collaborate with the utility.[98]

The final matter relates to the need to include a short term action plan in the IRP Report. Although the statutory requirements of Section 40 do not mandate that a utility include a Short Term Action plan, it is typical that most utility IRP Reports do include such a plan. PacifiCorp, as one example, states that "The 2019 IRP action plan identifies specific actions PacifiCorp will take over the next two (2) to four (4) years to deliver its preferred portfolio. Action items are based on the type and timing of resources in the preferred portfolio, findings from analysis completed over the course of portfolio modeling, and feedback received by stakeholders in the 2019 IRP public-input process."[99] PacifiCorp provides a table that details specific 2019 IRP action items by resource category, including existing and new resource, transmission, and DSM actions.

Other Considerations Recommendations

1. In future IRPs, the Company should create a stakeholder process to provide more opportunities for stakeholder involvement and input.
2. In future IRPs, the Company should develop a 3-year action plan that identifies all actions the Company intends to take in order to implement its IRP.

[98] http://lpscstar.louisiana.gov/Star/ViewFile.aspx?Id=95a4e806-45b4-4d5d-ae07-dd088a447363, at page 17 of the Louisiana Public Service Commission's April 20, 2012 Corrected IRP Order.
[99] https://www.pacificorp.com/content/dam/pcorp/documents/en/pacificorp/energy/integrated-resource-plan/2019_IRP_Volume_I.pdf, Chapter 9 – Action Plan.